

US EPA ARCHIVE DOCUMENT



**Basis for Denial of Petitions to Reconsider the CAA Section  
111(b) Standards of Performance for Greenhouse Gas  
Emissions from New, Modified, and Reconstructed Fossil  
Fuel-Fired Electric Utility Generating Units**

**April 2016**

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Basis for Denial of Petitions to Reconsider the CAA Section  
111(b) Standards of Performance for Greenhouse Gas Emissions  
from New, Modified, and Reconstructed Fossil Fuel-Fired  
Electric Utility Generating Units

U.S. Environmental Protection Agency  
Office of Air Quality Planning and Standards  
Sectors Policies and Programs Division  
Research Triangle Park, NC 27711

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**SUMMARY:** The U.S. Environmental Protection Agency (EPA) received six petitions for reconsideration of the final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, published in the Federal Register on October 23, 2015. The agency is denying five of these petitions, and deferring action on the petition of the Biogenic CO<sub>2</sub> Coalition.

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## I. Executive Summary

Pursuant to section 111(b) of the Clean Air Act (“the Act”), the EPA has promulgated new source performance standards that establish, for the first-time, standards of performance for greenhouse gas emissions from newly constructed, modified, and reconstructed fossil fuel-fired electric utility generating units (EGUs). 80 FR 64510 (Oct. 23, 2015). The standard for newly constructed steam generating EGUs reflects the level of CO<sub>2</sub> emission reduction achievable by a highly efficient supercritical pulverized coal-fired boiler implementing partial carbon capture and sequestration (CCS) technology. 80 FR 64545. The standard for newly constructed and reconstructed stationary combustion turbines reflects the performance of a modern, well-performing natural gas-fired combined cycle (NGCC) unit. 80 FR 64612.<sup>1</sup>

The EPA has received six petitions for reconsideration of the final standards of performance, focusing mostly on issues related to the standard of performance for newly constructed steam generating units and, more specifically, on the performance and cost of carbon capture technology. One petition maintains that the post-promulgation performance of carbon capture technology in actual operation at the Canadian SaskPower Boundary Dam Unit 3 facility shows that carbon capture is not yet adequately demonstrated at commercial scale. The EPA is denying reconsideration on this issue because, contrary to the petitioner’s contention, the facility’s performance, through March 2016, corroborates the EPA’s conclusion in the rulemaking that partial CCS is an adequately demonstrated technology within the meaning of CAA section 111(b). The same petition maintains that the SaskPower Boundary Dam facility uses a different carbon capture process than the one the EPA evaluated at proposal. This contention is incorrect. The petition further maintains that the EPA has not accounted for cost overruns at that facility. This contention is significantly exaggerated and not borne out by the facts.

The same petition maintains that the EPA failed to provide adequate public notice and opportunity to comment on the uncontrolled baseline emission rate (i.e., the emission rate of an uncontrolled coal-fired boiler) that it used as the starting point for calculating the percent of partial carbon capture needed to meet the applicable standard. In fact, the proposed rule provided ample public notice and opportunity to comment on this issue. The petition also maintains that the baseline is not achieved in practice, so that EPA’s cost estimates fail to account for some measure of increased boiler efficiency. The EPA disagrees with this contention, but even accepting the allegations, the costs of the standard would remain reasonable using the same methodology the EPA used in the rulemaking for assessing cost reasonableness. Another objection raised regarding partial CCS in this petition is that the EPA’s cost estimates of partial carbon capture reflect an inappropriate methodology for scaling down full carbon capture costs to partial capture costs. The EPA is denying reconsideration on this issue because the scaling methodology used in the rulemaking is well-established and normative, and the petition presents no legitimate reason to deviate from this standard methodology.

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<sup>1</sup> The EPA also set standards for reconstructed steam EGUs and for those units that make large modifications. The EPA withdrew proposed standards for modified stationary combustion turbines. This is discussed in greater detail in the preamble for the final rule. No petitioners raised issues associated with the standards for modified or reconstructed steam EGUs.

Other petitioners address the partial CCS-based standard for newly constructed steam generating EGUs, but these petitions simply reiterate issues already raised in their rulemaking comments. The EPA has already addressed these comments in the preamble to the final rule and in the Response to Comment document. These petitions are untimely and the EPA is therefore denying them.

The remaining petition addressing the partial CCS-based standard alleges that the rulemaking process was tainted by impermissible communications involving an EPA official and various members of non-governmental organizations. This petition's legal theory is flawed, and the petition rests on a plethora of inaccurate factual assertions. The EPA is accordingly denying this petition.

The final rule also contains standards for stationary combustion turbines, and one of the petitions discussed above also challenges the definition of "base load rating" included as part of that standard. The EPA is denying reconsideration of this issue because the decision to include the heat input from duct burners in the definition of "base load rating" was not only reasonable, but advantageous to the regulated industry.

Two of the petitions – from the Biogenic CO<sub>2</sub> Coalition and from the State of Wisconsin – raise issues associated with the agency's treatment of biomass emissions when co-fired with fossil fuels. The EPA is deferring action on this issue pending further on-going consideration of the underlying issue of whether and how to account for biomass, for purposes of compliance with applicable standards, when co-firing with fossil fuels.

The EPA is accordingly denying five of the six petitions for reconsideration, and deferring action on the remaining petition.

## II. Background

Section 307(d)(7)(B) of the CAA requires the EPA to convene a proceeding for reconsideration of a rule if a party raising an objection to the rule "can demonstrate to the Administrator that it was impracticable to raise such objection within [during the public comment period] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." The requirement to convene a proceeding to reconsider a rule is thus based on the petitioner demonstrating to the EPA both: (1) that it was impracticable to raise the objection during the comment period, or that the grounds for such objection arose after the comment period but within the time specified for judicial review (i.e., within 60 days after publication of the final rulemaking notice in the **Federal Register**, see CAA section 307(b)(1)); and (2) that the objection is of central relevance to the outcome of the rule.

In the EPA's view, an objection is of central relevance to the outcome of the final rule only if it provides substantial support for the argument that the promulgated regulation should be revised. See, e.g., the EPA's Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202 of the Clean Air Act, 75 FR 49556, 49561 (August 13, 2010); see also *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102, 125 (D.C. Cir. 2012) (acknowledging and applying the EPA's interpretation of the central relevance criterion); *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008) (holding that



a petitioner fails to demonstrate that its objection is of central relevance when the petitioner “vaguely alludes to EPA’s incorrect factual assumptions,” but “fails to support [its] assertion” (internal quotation omitted).<sup>2</sup> Put another way, an objection is of central relevance to the outcome of the rule if the EPA would have reached a different outcome in the rulemaking if the objection has merit. Should the EPA deny petitions for reconsideration, “EPA certainly may ... provide an explanation for that denial, including by providing support for that decision, without triggering a new round of notice and comment for the rule.” *Coalition for Responsible Regulation*, 684 F. 3d at 126.

The EPA has received six petitions for reconsideration of the CAA section 111(b) greenhouse gas (GHG) new source performance standard (NSPS) from the following entities: the Utility Air Regulatory Group (UARG); American Electric Power (AEP); Ameren Corp. (Ameren); the Energy and Environmental Legal Institute (EELI); State of Wisconsin (WI); and the Biogenic CO<sub>2</sub> Coalition. The EPA is denying all but the last of these petitions as not satisfying one or both of the statutory conditions for compelled reconsideration. The EPA is deferring action on the issue raised in the petitions of the Biogenic CO<sub>2</sub> Coalition and the State of Wisconsin regarding treatment of biomass emissions pending our further on-going consideration of the underlying issue of whether and how to account for biomass emissions when co-firing with fossil fuels. We discuss in turn each of the five petitions we are denying.

### III. The Petitions

#### A. *Petition of Utility Air Regulatory Group (UARG)*

UARG’s petition seeks reconsideration of several issues. First, UARG maintains that the operational experience with the newly installed carbon capture system<sup>3</sup> at the SaskPower Boundary Dam Unit 3 (BD3) belies EPA’s reliance on this facility’s operating experience in support of the agency’s conclusion that carbon capture is an adequately demonstrated technology within the meaning of section 111 of the Act. Specifically, UARG maintains that BD3’s carbon capture system has experienced significant operating issues, including prolonged shutdowns, and has failed to reach its 90 percent capture design level. The petition further states that the company has incurred financial penalties for failing to provide contractually agreed upon amounts of CO<sub>2</sub> to its sequestration site (where the CO<sub>2</sub> is used for enhanced oil recovery (EOR)), again because of these operational shutdowns and other problems. The petition suggests that these operational issues have caused SaskPower to reconsider its announced plans to retrofit others of its units with carbon capture systems, quoting the company’s chief executive officer as stating, “[w]e need a year of stable operation near maximum performance to really test the

<sup>2</sup> See also CAA sections 307(d)(8) and (d)(9)(D)(iii), which likewise apply a “central relevance” criterion to judicial review of alleged procedural errors, requiring that the error be essentially outcome-determinative: “so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been substantially changed” if a procedural error had not occurred.

<sup>3</sup> UARG refers to “CCS” – carbon capture and sequestration (or storage) – throughout this part of its petition, but the issues it raises relate entirely to operation of the carbon capture system, not the transportation or sequestration/storage parts of the project (beyond its assertion that Boundary Dam has failed to provide the volume of CO<sub>2</sub> for sequestration specified by contract and has incurred financial penalties as a result).

technology and commercial viability going forward” (UARG petition Exh. I). UARG also states that the carbon capture system in use at BD3 served as the basis for the Department of Energy’s National Energy Technology Laboratory (NETL) cost estimates for carbon capture systems, which were in turn used by the EPA for its cost estimations in the rulemaking, and that BD3 is now experiencing costs not accounted for in the NETL estimates.

Finally, UARG states that BD3 has not shown that it could achieve the promulgated standard of 1,400 lb CO<sub>2</sub>/MWh-g (demonstrated on a 12-month basis). The petition contains various supporting exhibits, most of which are press accounts of Saskatchewan (Canada) Parliamentary debates discussing BD3’s operations. The petition claims that this information is of central relevance since the performance of BD3 provides the primary rationale for the EPA’s finding that carbon capture is adequately demonstrated. (UARG Petition p. 8) Because BD3’s operating history reflects post-proposal, and in many instances, post-promulgation developments, commenters could not have been presented the information to the EPA during the rulemaking.

The second issue raised in the UARG petition (effectively joined by petitioners AEP and State of Wisconsin, which raise the identical issue in their petitions) is that the EPA selected an arbitrary uncontrolled baseline CO<sub>2</sub> emission rate from which to calculate quantified CO<sub>2</sub> emission reductions, and did so without providing adequate opportunity for public comment. Specifically, UARG maintains that at proposal the EPA indicated that the Best System of Emission Reduction (BSER) for CO<sub>2</sub> was partial CO<sub>2</sub> capture applied to an emission stream reflecting performance of a supercritical pulverized coal boiler (SCPC). The baseline should thus be the initial performance of a SCPC unit. UARG states that “[t]he proposed GHG NSPS did not in any way address the baseline emission rate for new SCPC units or analyze the proposed standard’s achievability for such units. Instead, the proposal only conceptually described ‘the emission reductions that can be achieved by an IGCC [Integrated Gas Combined Cycle] with a single-stage ... reactor and a two-stage acid gas removal system’ – i.e., an IGCC applying pre-combustion CCS,” citing to 79 FR 1470 (UARG Petition p. 9). In the final rule, according to UARG, the BSER is partial CO<sub>2</sub> capture applied to an emission stream reflecting performance of an ultra-supercritical pulverized coal (USCPC) boiler, performing at hitherto undisclosed levels of between 1,618 to 1,737 lb CO<sub>2</sub>/MWh (depending on the type of coal being utilized). UARG maintains that SCPC units cannot meet this baseline level, and therefore that the final standard would not be achievable without additional carbon capture, which UARG maintains the EPA has implicitly found would not be cost-effective. UARG further maintains that even ultra-supercritical boilers cannot meet the baseline levels over the 12-month operating period specified in the rule for compliance. (UARG Pet. p. 13.) According to the Petition, the issue is of central relevance to the rule’s outcome because it pertains to the standard itself.

UARG’s third issue relates to the EPA’s estimates of CCS capital costs, which UARG maintains are arbitrarily low. UARG asserts that the EPA “did not address the capital cost of partial CCS” at proposal (UARG Pet. p. 14), and that its estimates of capital costs for the final rule are erroneous because the costs a) do not reflect costs of actual projects utilizing CCS; b) fail to reflect the proper baseline, a well-operated SCPC (reiterating issue 2 above); c) fail to include a design margin; and d) are based on NETL reports that misapply NETL’s own methodology for estimating costs when scaling. The issue is of central relevance, according to the Petition, because the purported costing errors call into question the EPA’s conclusion that CCS is an adequately demonstrated technology, considering its cost.

The Petition also seeks reconsideration of two issues that are ancillary to the promulgated standards of performance. UARG maintains that the EPA changed the applicability criteria for stationary combustion turbines without proper notice, and that this issue is of central relevance to the rule's outcome since it relates to which units are subject to the standard of performance. Specifically, UARG argues that the EPA should reconsider its decision to include the heat input from duct burners in the definition of "base load rating," 40 CFR 60.5580, because UARG did not have an opportunity to comment on this aspect of the final rule. UARG explains that this change affects the applicability criteria for stationary combustion turbines, which only subject turbines that have "a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel)" to the requirements of the rule. 40 CFR 60.5509(a)(1). UARG objects to the inclusion of the heat input from duct burners in the definition of "base load rating" because the approach is allegedly inconsistent with the approach taken in the proposed rule and the EPA's historical treatment of stationary combustion turbines under Subpart KKKK. UARG asserts that the issue is centrally relevant to the Rule because it implicates the fundamental question of what units are subject to the 111(b) GHG NSPS.

The last issue raised in UARG's petition is that the final rule unreasonably restricts the entities who may submit electronic reports under the final standard. The petition maintains that the final rule purportedly reflected public comments submitted by UARG, but misinterpreted those comments. UARG maintains that this issue is of central relevance to the outcome of the rule as it relates to who can make submissions under the rule.

*B. Petition of American Electric Power (AEP)*

American Electric Power Co. (AEP) maintains that the EPA misinterpreted and misapplied information relating to a project whereby AEP retrofitted one of its operating plants (the Mountaineer Power Plant, New Haven, WV) with CCS. AEP maintains that it (and others) submitted extensive comments regarding the Mountaineer Power Plant retrofit, and that, despite these comments, the final rule unaccountably still indicates that the Mountaineer project provides support for partial CCS being an appropriate best system of emission reduction. The petition does not maintain that AEP lacked adequate notice of issues pertaining to the Mountaineer project, or that the issue of the plant's performance is of central relevance to the outcome of the rulemaking.

AEP also maintains that certain alternative compliance options for meeting the standard, namely using natural gas co-firing in either a steam generating unit (boiler) or Integrated Gasification Combined Cycle (IGCC) unit, are not technically demonstrated, and seeks reconsideration of this finding. The State of Wisconsin likewise seeks reconsideration of this finding, for similar reasons. Finally, as noted above, AEP also contends that the EPA selected an arbitrary uncontrolled baseline CO<sub>2</sub> emission rate from which to calculate quantified CO<sub>2</sub> emission reductions, and did so without providing adequate opportunity for public comment.

*C. Petition of Ameren Corp.*

Ameren Corp. (Ameren) maintains that the CAA section 111(b) GHG NSPS, the CAA section 111(d) existing source standards of performance and emission guidelines, and the proposed federal plan requirements are closely intertwined and should be considered as a single unit of rules. The petition then mentions a series of issues relating exclusively to the CAA

section 111(d) existing source standards and emission guidelines as (purportedly) necessitating reconsideration.<sup>4</sup> The petition does not seek reconsideration of any specific issue in the section 111(b) rulemaking. The only mention of an issue specific to the section 111(b) NSPS is an allegation that partial CCS is not yet adequately demonstrated (Ameren Petition p. 24) (with a supporting quotation that relates to full CCS rather than partial CCS). The petition does not allege that Ameren lacked notice and opportunity to comment on this issue.

*D. Petition of State of Wisconsin*

The State of Wisconsin seeks reconsideration of various issues raised in its public comments, which it asserts that the EPA failed to address. These issues include whether CCS is adequately demonstrated when it is an “emerging technology”; whether the standard is arbitrary because it is more stringent than a best available control technology (BACT) limit for a coal-fired plant in Wisconsin; and whether the standard impermissibly disadvantages Wisconsin sources for various reasons, including lack of geologic sequestration capacity within the state. The petition further maintains that the EPA did not account for the full cost of transporting captured CO<sub>2</sub>, at least for Wisconsin sources. Additionally, with respect to combustion turbines, the petition argues that EPA set a standard of performance for base load units that cannot be achieved by simple cycle technology. Finally, the petition raises a number of issues in common with the other petitions, as noted above.

Similar to the AEP petition, the Wisconsin petition maintains that co-firing of natural gas in either a steam generating unit (boiler) or Integrated Gasification Combined Cycle (IGCC) unit, has not been technically demonstrated, and the petition seeks reconsideration of the EPA’s finding that natural gas co-firing can serve as an alternative compliance option for meeting the standards. Finally, as noted above, the petition also contends that the EPA selected an arbitrary uncontrolled baseline CO<sub>2</sub> emission rate from which to calculate quantified CO<sub>2</sub> emission reductions, and did so without providing adequate opportunity for public comment. The petition does not address the section 307(d) criteria for granting reconsideration.

*E. Petition of Energy and Environment Legal Institute (EELI)*

EELI maintains that the final standard of performance is tainted due to pre-proposal communications between a particular EPA official and representatives of environmental non-governmental organizations (NGOs), which the petition characterizes as illegal *ex parte* contacts that are of central relevance to this proceeding because of the purported influence the communications had on the standard.

#### **IV. Response to Petitions**

*A. Response to UARG Petition*

1. Performance of SaskPower Boundary Dam Unit 3 (“BD3”)

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<sup>4</sup> Note that Ameren Corp. also submitted essentially the same petition to the agency requesting reconsideration of these issues in the CAA section 111(d) emission guidelines.

SaskPower's Boundary Dam has installed retrofit "full CCS"<sup>5</sup> technology on its Unit 3 boiler and is currently operating it at commercial scale. UARG, in essence, maintains that the post-proposal/post-promulgation performance of BD3 shows that the CCS system is not working, and, therefore shows that the technology is not adequately demonstrated at the facility. The petition further states that since the performance of the BD3 system was the critical element in the EPA's finding that partial CCS is an adequately demonstrated technology, the unit's subsequent operational failures undermine the entirety of the EPA's finding, and is necessarily an issue of central relevance to the outcome of the rulemaking. UARG further maintains that it lacked opportunity to comment on these issues because the critical elements of the BD3 performance occurred either after proposal or after the August 2015 promulgation date of the final standards.

The EPA agrees that the grounds for UARG's objection arose after the public comment period, but disagrees that the objection is of central relevance to the rule's outcome because the EPA did not rely solely on the expected performance of BD3 (see 80 FR 64550-556) and because the actual performance of BD3 confirms that partial CCS is adequately demonstrated at the facility, and thus corroborates the EPA's finding that the technology is adequately demonstrated.

The suggestion that BD3 has experienced operational failures calling into question the reliability, feasibility, or demonstrability of the carbon capture technology is greatly exaggerated and essentially incorrect. As described below, the CO<sub>2</sub> capture system at BD3 is operating successfully, the unit meets the Canadian performance standard for CO<sub>2</sub> emissions (which is more stringent than the U.S. standard), and it is producing more CO<sub>2</sub> for enhanced oil recovery than called for by contract. Operational issues in the first year of operation were related largely to ancillary systems and not to the carbon capture system, and appear to have been successfully resolved.

The BD3 carbon capture system commenced operation in October 2014. The system was shut down for two weeks in June 2015 for maintenance, and for nearly two months (most of September and all of October) in the fall of the same year for further maintenance.<sup>6</sup> The system has operated with high reliability since.<sup>7</sup> BD3 continued to generate electricity during the entire 18-month period, with the exception of the September maintenance period.<sup>8</sup>

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<sup>5</sup> As explained in both the proposal (79 FR 1469) and the final standards (80 FR 64548), "full CCS" means that the system is designed to capture 90 percent (or greater) of the CO<sub>2</sub> emissions from the plant usually by treating the entire combustion flue gas or syngas stream. "Full CCS" is distinguished from "partial CCS" in that the latter is a system that is designed to capture some amount less than 90 percent of the CO<sub>2</sub> emissions, often by treating only a portion (or slip stream) of the combustion flue gas or syngas stream.

<sup>6</sup> SaskPower Report March 2016 posted at <http://www.saskpower.com/about-us/blog/bd3-status-update-march-2016/>.

<sup>7</sup> Id., indicating that the system "was operational 82 of 91 days of the year, primarily due to planned maintenance, for a 90% reliability factor in the first quarter of 2016."

<sup>8</sup> Id.



It is not unusual for plants to experience operational issues after first installing and operating a complex technical system. See, e.g., 79 FR 1482.<sup>9</sup> However, according to SaskPower, most of the technical issues experienced by the unit in its initial year of operation involved ancillary equipment and control systems rather than technical issues that are directly attributable to the carbon capture system itself.<sup>10</sup> For example, there were idiosyncratic issues associated with the design or misplacement of ordinary components – such as exhaust valves being installed too near intake valves. There was also a delay associated with the need to install a new, larger storage tank for the amine solvent and then to fix the tank, which the company described as being delivered with visible hairline cracks in the tank floor.<sup>11</sup> In addition, in the initial months of operation, the unit experienced some operational difficulties associated with SaskPower's ability to control the amine regeneration temperature because of a leaky steam valve. This resulted in overheating and subsequent degradation of the amine solvent.<sup>12</sup> While the leaky steam valve resulted in an overall degradation of the performance of the carbon capture system, few would characterize steam valve technology as “not adequately demonstrated” or “first-of-a-kind”. Nor is a cracked storage tank the type of development that raises issues regarding the feasibility of carbon capture technology.

The company brought the carbon capture system down in September and October of 2015 to address various operational issues related to sodium-based sub-micron particles that were fouling demisters at the exit of the SO<sub>2</sub> scrubber upstream of the carbon capture system.<sup>13</sup> The issue was resolved and the carbon capture system resumed operation in November 2015.

The system has demonstrated high rates of CO<sub>2</sub> capture since its initial coming on-line. In its initial months of operation, the system operated at a relatively constant CO<sub>2</sub> removal rate of approximately 61.5 percent of its design capacity (or approximately 1,700 tons of CO<sub>2</sub> per day). Since November 2015, after the two month hiatus, the unit captured approximately 60,000 tons of CO<sub>2</sub> in November 2015 and approximately 61,000 tons of CO<sub>2</sub> in December 2015, capture

<sup>9</sup> See also letter from SaskPower President and CEO Mike Marsh to Administrator Gina McCarthy (Nov. 17, 2015) (“[w]e have achieved an 80 per cent capture rate in our early operations; however, the capture rate has fluctuated over the course of the year. Since the launch, SaskPower has experience various problems with a number of sub-systems within the process and has worked to develop solution and to fix them. These challenges are not uncommon in a large-scale industrial project during the early stages of operation....”).

<sup>10</sup> Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016; Email from Mr. Mike Monea (SaskPower) to Dr. Nick Hutson (EPA), February 2, 2016).

<sup>11</sup> Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016. See also SaskPower Press Release of Sept. 14, 2015 (<http://www.saskpower.com/about-us/media-information/newsreleases/large-piece-of-saskpower-equipment-makes-its-way-from-saskatoon-to-estevan/>), and UARG Petition Exh. G p. 2 which note the replacement of the amine storage tank, and note the storage tank's very substantial size. Exh. G (at p. 2) also notes the issue of the leaky valve.

<sup>12</sup> Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016.

<sup>13</sup> <http://www.saskpower.com/about-us/blog/bd3-status-update-january-2016/>; Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016. The system was also down for maintenance for two weeks in June 2015.

rates exceeding 70 percent of design capacity.<sup>14</sup> In January 2016, the unit captured approximately 85,000 tons<sup>15</sup> – slightly better than 100 percent of design capacity, and an amount that exceeds the monthly quantity of CO<sub>2</sub> that SaskPower has contracted to provide to Cenovus Co. for EOR operations.<sup>16</sup> Capture rates for February and March, 2016, are approximately 60 and 100 percent of design capacity respectively.<sup>17</sup> SaskPower has, at several times, conducted so-called nameplate testing, designed to test the capture limits of the facility, and was able to achieve the intended 90 percent capture rates on those occasions.<sup>18</sup> The company has stated publicly that it expects the carbon capture system to be operational 85 percent of the time in 2016 (allowing time off for routine scheduled maintenance) and to capture 800,000 tons of CO<sub>2</sub> over that year, a projected average capture rate of approximately 80 percent of design capacity.<sup>19</sup>

Over the one-year operating period from October 2014 through September 2015, even considering the facility downtime, BD3 captured approximately 415,000 tons of CO<sub>2</sub>. This is a capture rate exceeding 40 percent,<sup>20</sup> which is significantly more efficient than the 12-month annual capture rate (reflecting partial carbon capture at an annual rate of approximately 16 to 23 percent depending on coal type) on which the section 111(b) new source standard is predicated.<sup>21</sup> See 80 FR 64573-74. Indeed, the plant's capture amount would have comfortably satisfied the standard for a plant with five times the volume of CO<sub>2</sub> emissions (i.e., a 500 MW SCPC plant).<sup>22</sup> From February 2015 through January 2016, the plant captured 625,000 tons of CO<sub>2</sub>, a capture

<sup>14</sup> Letter of January 20, 2016, from SaskPower CEO Mike Marsh to EPA Administrator Gina McCarthy, p. 1.

<sup>15</sup> "In some months routine maintenance and inspection is planned and in other months, such as January, the facility can be operated nearly 100 per cent of the time. Over a year, we expect the facility to be up and running approximately 85 percent of the time... It allowed us to capture and sequester a record 84,976 tonnes of carbon dioxide. We continue to target the capture of 800,000 tonnes this year." SaskPower Report January 2016 posted at <http://www.saskpower.com/about-us/blog/bd3-status-update-january-2016/>.

<sup>16</sup> Email from Mr. Mike Monea (SaskPower) to Dr. Nick Hutson (EPA), Feb. 2, 2016; UARG Petition Exh. B.

<sup>17</sup> SaskPower Report March 2016 posted at <http://www.saskpower.com/about-us/blog/bd3-status-update-march-2016/>.

<sup>18</sup> Letter from Saskpower CEO Mike Marsh to Administrator Gina McCarthy, Nov. 17, 2015 p. 1; Letter from Saskpower CEO Mike Marsh to Administrator Gina McCarthy, Jan. 20, 2016 p. 1; email of February 2, 2016; see also the chart in UARG Petition Exh. H and Exh. J p. 2-3 showing individual days where the plant achieved a 90 percent capture rate. Boundary Dam conducted its most recent nameplate testing in December, 2015.

<sup>19</sup> SaskPower Report January 2016 posted at <http://www.saskpower.com/about-us/blog/bd3-status-update-january-2016/>.

<sup>20</sup> The system is designed to capture 1 million tons of CO<sub>2</sub> per year. UARG Petition Exh. D; see also id. Exh. B, D, E p. 2, and G (all noting 400,000 tons of CO<sub>2</sub> captured in the initial year of operation), and Exh. C and D (noting 40% + capture rate in initial year of operation).

<sup>21</sup> Letter of January 20, 2016, from CEO Mike Marsh to Administrator McCarthy p. 1; see also Exh. B, D, E (p. 2), H (p. 1 of 4), and J (p. 2-3) of UARG's petition, all of which likewise show that Boundary Dam has recovered more CO<sub>2</sub> over its initial 12 months of operation than would be required under the CAA section 111(b) NSPS.

<sup>22</sup> See Table 12 of preamble to final rule (80 FR 64574) showing capture of 354,000 tons of CO<sub>2</sub> annually would be required for a 500 MW SCPC plant to meet the promulgated standard.

rate exceeding 60 percent, which is, as noted, well in excess of what the NSPS requires (notwithstanding downtime for the system in June, September, and October).<sup>23</sup> The initial capture rates for the months immediately following the two month maintenance period also greatly exceed those on which the NSPS are predicated, as does the plant's projected 2016 capture rate.<sup>24</sup>

Equally important is that the plant's initial operational issues appear to be resolved, and that most of these operational issues were related, in any case, to ancillary systems at the plant, not to the carbon capture system. The unit's operation also bears out the EPA's prediction that the 12-month averaging period is "forgiving" and accommodates significant operational variability. 80 FR 64573 (12-month averaging period is "very forgiving of short-term excursions that can be associated with non-routine events such as start-ups"); Achievability TSD (July 31, 2015) at pp. 1-2 (similar finding).

Importantly, the carbon capture system at BD3 is a retrofit to an existing unit, which poses special complexities and difficulties that a new source would not experience.<sup>25</sup> One can reasonably assume that future plants will benefit from BD3's operational and startup experience, and need not encounter the same issues. See 80 FR 64565-66. BD3's carbon capture operations remain transparent to the general public with SaskPower providing regular updates on plant performance that are posted on their website [www.saskpower.com](http://www.saskpower.com) (listed as "BD3 Update" on the site). In addition, SaskPower and BHP Billiton have established the "Carbon Capture and Storage Knowledge Centre" to help advance CCS as a means of managing greenhouse gas emissions.<sup>26</sup> SaskPower is also helping advance CCS knowledge and technology through the creation of the Shand Carbon Capture Test Facility (CCTF).<sup>27</sup> The CCTF provides technology developers with an opportunity to test new and emerging carbon capture systems for controlling carbon emissions from coal-fired power plants.

Although BD3's early operational issues reduced the volume of CO<sub>2</sub> it was able to deliver for EOR, because it has resolved those issues, it now "satisfies the volume needs of our carbon dioxide buyer," and, since November 2015, is generating more CO<sub>2</sub> than specified by

<sup>23</sup> <http://www.saskpower.com/about-us/blog/bd3-status-update-january-2016>.

<sup>24</sup> The unit has also achieved the more stringent Canadian emission limitation of 420 kg CO<sub>2</sub>/MWh (926 lb CO<sub>2</sub>/MWh) per calendar year. Email from Mr. Mike Monea (SaskPower) to Dr. Nick Hutson (EPA), Feb. 2, 2016.

<sup>25</sup> See 80 FR 64551 ("In fact, retrofit of [CCS] technology at an existing unit can be more challenging than incorporating the technology into the design of a new facility"); id, at 64557 ("Much has been written about the complexities of adding CCS systems to fossil fuel-fired power plants. Some commenters argued that the EPA minimized – or even ignored – these publicly-voiced concerns in the discussion presented in the ... proposal. On the contrary, the EPA has not minimized or ignored these complexities, but it is important to realize that most of these statements come in a different context: [n]amely, implementing full CCS, or retrofitting CCS onto existing power plants"); see also Comment Response 6.3-47 (special difficulties experienced by American Electric Power Mountaineer project due to it being a retrofit to an existing facility) and response B *infra* (response to petition of American Electric Power).

<sup>26</sup> <http://www.bhpbilliton.com/investors/news/bhp-billiton-and-saskpower-establish-carbon-capture-and-storage-knowledge-centre>.

<sup>27</sup> <http://saskpowerccs.com/ccs-projects/shand-carbon-capture-test-facility/>.



contract.<sup>28</sup> The company indicates that revenues from EOR will exceed any contract penalties for the 2015 operating year.<sup>29</sup> Moreover, some of the foregone revenue resulted from BD3 generating more CO<sub>2</sub> in its initial months of operation than the EOR buyer could accommodate.<sup>30</sup>

The petition likewise quotes SaskPower CEO Mike Marsh as stating “we need a year of stable operation near maximum performance to really test the technology and commercial viability going forward”. (UARG Petition Exh. I, p. 1.) The statement is in the context of whether to retrofit full-scale CCS on the company’s fleet of coal boilers, and thus of minimal relevance in deciding here whether to reconsider a standard reflecting performance of partial capture of CO<sub>2</sub> by a newly constructed source. In addition, there is no requirement under the Act or in case law that a technology operate for any given period before it can be considered to be adequately demonstrated, and, in fact, under certain circumstances, the EPA may determine that a technology is adequately demonstrated even before it begins to operate. Moreover, SaskPower evidently views the carbon capture technology as operating successfully, as shown by its public letters and statements, which are part of the record here. Furthermore, as noted in the final rule, the BD3 project is only one of the examples of post-combustion capture that the agency relied on in its determination that post-combustion partial CCS has been adequately demonstrated. See 80 FR 64548.

In any case, the quote from CEO Marsh relates to SaskPower’s decision about whether or not to retrofit additional coal-fired units with CCS technology. As the EPA noted in both the proposed and final CAA 111(b) standards, coal-fired units currently face tremendous competitive pressure from other generation options – especially from natural gas-fired combustion turbines and renewable energy sources. See, e.g., 80 FR 64558-59 and 64641-42; see generally RIA chapter 4. SaskPower is faced with a requirement to either retire its aging fleet of coal-fired boilers or retrofit them with CCS technology (in order to meet the Canadian emission standard). Given these options, it certainly makes sense that the company would allow the BD3 system to operate for some time so that the company can “really test” not just the performance of the technology, but also the commercial viability of retrofitting its fleet of coal-fired boilers with the CCS system vis-à-vis other investment options for generating electricity.

The petition also suggests that BD3’s failure to operate at a day-to-day 90 percent capture rate shows the technology is not operating reliably because the plant system is designed to achieve a 90 percent capture rate. See, e.g., UARG Pet. Exh J pp. 2-2 to 2-3. The EPA disagrees. The plant has, in fact, achieved 90 percent capture when doing nameplate testing (i.e., pushing the technology to its design limit) and has operated at capture rates exceeding even its 90 percent design level, but the more important point is that the plant has operated and is operating reliably, and is now providing more CO<sub>2</sub> monthly than required by contract. It is meeting the Canadian

<sup>28</sup> Letter from Saskpower CEO Mike Marsh to Administrator Gina McCarthy, Jan. 20, 2016 p. 1.

<sup>29</sup> Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016; UARG Petition Exh. D p. 3.

<sup>30</sup> Email from Mr. Mike Monea (SaskPower) to Dr. Nick Hutson (EPA), Feb. 20, 2015 (EPA-HQ-OAR-2013-0495-11699) (“We are running about 75% capture, roughly 2,600 tonnes/d of 99.999% CO<sub>2</sub>. Cenovus Energy is phasing in our CO<sub>2</sub> so we will have five months of lower sales for EOR to Cenovus.”); see also UARG Pet. Exh. D p. 2 (“In some of the months, it was running more efficient than Cenovus would take”).

CO<sub>2</sub> emission standards (which are more stringent than the NSPS at issue here). Even more basically, operational ‘hiccups’ in an initial year of operation are to be expected (see e.g., 79 FR 1482 (Jan. 14, 2014)), and do not, by themselves, show that a control technology is infeasible, or otherwise not demonstrated. The EPA believes that is the case here where plant managers and executives indicate that the operational problems involved are resolved (and, for the most part, were not attributable to the carbon capture system itself), and the plant is operating on a highly successful upward trajectory.

The EPA thus is denying this aspect of the petition as not showing that the objection is of central relevance to the outcome of the rulemaking. As just noted, the EPA did not project that plants would operate CCS without experiencing some initial operational issues,<sup>31</sup> and established a standard with an extended averaging time to provide an ample compliance margin. See 79 FR 1481; 80 FR 64573. BD3 is operating successfully, and has demonstrated that it can achieve capture rates well in excess of its contractual obligations, as well as sufficient to achieve compliance with the (more stringent) Canadian CO<sub>2</sub> emission standard. More importantly, the retrofit carbon capture system at BD3 has demonstrated the ability to achieve carbon capture rates, over an extended averaging time, that are far in excess of the capture rates needed to comply with the standard established by the EPA for new steam generating EGUs under the subject rulemaking. The EPA thus believes that Boundary Dam’s performance corroborates rather than undermines a finding that partial CCS is an adequately demonstrated technology, within the meaning of section 111(b) of the Act.

## 2. Use of NETL (2015) Cost Estimates/Cost of Shell Cansolv Carbon Capture Technology

UARG also maintains that BD3 uses the Shell Cansolv carbon capture process, that the Cansolv process served as the basis for cost estimates from a National Energy Technology Laboratory (NETL) study that was issued in June 2015 (after the comment period), and that those cost estimates do not (and could not) reflect cost overruns experienced by BD3. More generally, UARG states that the EPA based its cost estimates for carbon capture at proposal on a different carbon capture technology, and maintains broadly that the public lacked opportunity to comment on the 2015 NETL cost estimates. UARG Petition pp. 7-8. None of these contentions justify reconsideration, and the EPA is accordingly denying this part of the petition.

It is well settled that agencies may rely on studies not subjected to notice and comment where those studies serve as additional support for the data and conclusions in a proposal, particularly where there is no change to the methodology by which the information is developed and assessed. *See, e.g., Chamber of Commerce v. SEC*, 443 F. 3d 890, 900 (D.C. Cir. 2006) (“further notice and comment are not required when additional fact gathering merely supplements information in the rulemaking record by checking or confirming prior assessments without changing methodology” (citing *Solite v. EPA*, 952 F.2d 473, 485 (D.C. Cir. 1991))). There was no methodological change here. The 2015 NETL report was an update (listed as “Revision 3”) of the studies that the EPA used at proposal. As is further explained below, all of these updates use the same basic methodology (e.g., a component-by-component cost evaluation of a post-combustion CCS system with the same key financial assumptions). The EPA used the

<sup>31</sup> See, e.g., 79 FR 1482 (noting that a potential 84-month averaging time “offers increased operational flexibility and will tend to compensate for short-term emission excursions, which may especially occur at initial startup of the facility and the CCS system”).

NETL studies to derive the cost estimates presented in the proposal and then used the updated NETL studies to derive cost estimates for the final standards. The EPA then, as at proposal, compared those estimates to the cost of non-fossil fuel-fired electricity generating technologies, in particular technologies providing baseload dispatchable power, using the Levelized Cost of Electricity (LCOE) metric. Compare 79 FR 1475-78 and 80 FR 64560-563. As at proposal, carbon capture is considered to be a technology with cost estimates reflecting a next commercial offering (or next-of-a-kind) of the technology.<sup>32</sup> As at proposal, the updated study remains a Class 4 feasibility study, with cost estimates presented with the same range (-15 to +30 percent uncertainty on the capital cost).<sup>33</sup> Consistent with earlier studies, the updated NETL study assumes high-risk financing for the carbon capture system.<sup>34</sup> There is the same level of transparency in each study, based on identical overall methodology for assessing and presenting costs for each operating system.

The 2015 NETL cost information supplements and corroborates information used at proposal. First, UARG is not correct in stating that the EPA considered a different carbon capture technology in its cost estimates for the final rule as compared to the one it used at proposal. For both the proposed and final standards, the EPA's cost estimates were for a new, highly efficient, coal-fired boiler implementing partial post-combustion CCS through the use of an amine-based capture system which scrubs CO<sub>2</sub> from a slip stream of the post-combustion flue gas. The CCS capture system (i.e., the equipment) was the same in both studies – only the solvents differ.<sup>35</sup> In the proposed action, the NETL studies that served as the basis for those costs assumed that the post-combustion CCS system used the Fluor Econamine solvent.<sup>36</sup> For the final action, the EPA relied on updated NETL studies that assumed the use of the Shell Cansolv solvent.<sup>37</sup> The Shell Cansolv amine solvent was used in the updated studies because it is the better performing solvent.<sup>38</sup> As it happens, BD3 uses the Cansolv solvent in its carbon capture system.

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<sup>32</sup> 79 FR 1476; Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3", DOE/NETL-2015/1723 (July 6, 2015) ("NETL 2015") (EPA-HQ-OAR-2013-0495-11341 ("NETL 2015")), p. 38.

<sup>33</sup> Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture, Revision 1, DOE/NETL-2011/1498 ("NETL 2013") (EPA-HQ-OAR-2013-0495-11635) p. 37; 80 FR 64567.

<sup>34</sup> NETL 2015 p.17, Exh. ES-4; see also NETL 2013 pp. 41-42.

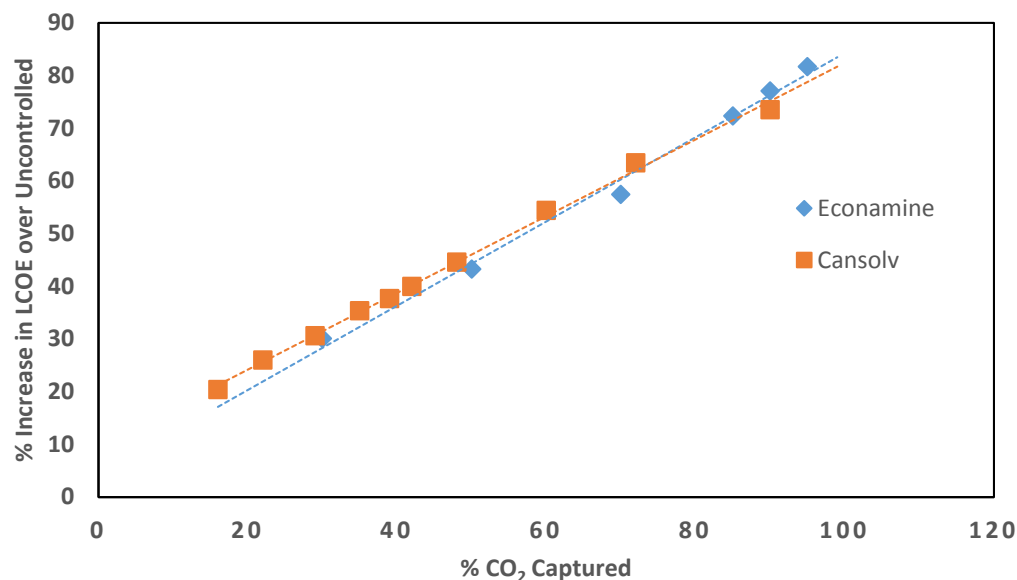
<sup>35</sup> Each study evaluates (individual component by individual component) the following systems: coal sorbent handling, coal preparation and feed, feedwater, boiler and accessories, flue gas cleanup, CO<sub>2</sub> recovery, ducting and stack, steam turbine generator and auxiliaries, cooling water, accessory electric plant, and ash and spent sorbent recovery and handling. See NETL 2013 pp. 109-115; NETL 2015 pp. 103-108.

<sup>36</sup> NETL 2013 pp. 65-69 (EPA-HQ-OAR-2013-0495-11635).

<sup>37</sup> "Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO<sub>2</sub> Capture Rate in Coal-Fired Power Plants" DOE/NETL-2015/1720, pp. 6-7 (EPA-HQ-OAR-2013-0495-11661); NETL 2015 pp. 59-68.

<sup>38</sup> In addition, in considering the updated studies, the EPA was responding to comments, including from Petitioner UARG, urging the EPA to consider costs reflecting actual operation of carbon capture. See 80 FR 64567 ("[t]he EPA used this latest version of the NETL studies not only to assure that it considers the most up-to-date information but also to address public comments criticizing the proposal for relying on out-of-date information"). This fact further obviates the Petitioner's notice and comment concerns. See

Also, as shown in Figure 1 below, the overall estimated costs for the partial CO<sub>2</sub> capture system in the 2015 updated NETL study (presented as the percent increase in cost of the system over an uncontrolled (i.e., no carbon capture) baseline) are virtually identical to those at proposal for the same post-combustion capture system using a different solvent.<sup>39</sup> See also 80 FR 64567-69 (other studies and industry information which corroborate NETL cost estimates for CCS). Under these circumstances, the EPA was not obligated to re-notice the cost estimates, or the NETL report itself.



**Figure 1. Comparison of Percent Increase in LCOE from Proposal (Econamine solvent) and Final (Cansolv solvent)<sup>40</sup>**

UARG nonetheless maintains that these estimated costs don't reflect costs actually experienced by BD3. However, as explained earlier in Section III.A.1, the UARG petition greatly exaggerates the degree of BD3's performance difficulties. Moreover, as also explained

*Chemical Manufacturers Ass'n v. EPA*, 870 F. 2d 177, 201-02 (5<sup>th</sup> Cir. 1989) (no further notice and opportunity for comment required where "[t]he EPA did not supplant its economic-impact study, or replace its original data with completely new and different data, but, in response to industry criticisms, updated and expanded one of several data sources"); see also *Community Nutrition Inst. v. Block*, 749 F. 2d 58 (D.C. Cir. 1984) ("Rulemaking proceedings would never end if an agency's response to comments must always be made the subject of additional comments", and this response can take the form of further corroborative scientific studies without triggering a new round of notice and comment) (Scalia, J.).

<sup>39</sup> These cost estimates reflect updated estimates for certain common costs between the two technologies, notably labor and material costs.

<sup>40</sup> Exhibit ES-14 from NETL 2013 ("Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture," Rev 1 (September 19, 2013)), DOE/NETL-2011/1498; and Exhibit A-3 from "Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO<sub>2</sub> Capture Rate in Coal-Fired Power Plants" (June 22, 2015), DOE/NETL-2015/1720 (EPA-HQ-OAR-2013-0495-11661).

above, most of those performance issues relate to ancillary equipment and systems other than those specifically for carbon capture. These are facility-specific issues (e.g., cracks in the amine storage tank) which need not be assumed to be generally applicable. Moreover, the EPA evaluated cost estimates as a range (consistent with the NETL methodology), so that the capital costs could range up to 30 percent higher. 80 FR 64567. The cost estimates that the EPA used in the rule thus account for some measure of potential cost increases.

UARG made particular note of the carbon capture system not capturing sufficient CO<sub>2</sub> for BD3 to meet its contractual obligations, incurring financial penalties and lost revenues as a result. See UARG Petition p. 7. Any costs incurred by SaskPower related to EOR are irrelevant here since the EPA's cost estimates assume geologic sequestration of the captured CO<sub>2</sub> rather than use in EOR operations. 80 FR 64564/2. In any case, UARG exaggerates the extent of SaskPower's difficulties. As again noted above, the company expects to show a profit, even in the short-term, from sales of CO<sub>2</sub> and is presently not only meeting its contractual targets but actually generating more CO<sub>2</sub> than the EOR operator can accommodate.<sup>41</sup> Under these circumstances, UARG's information is not of central relevance to the outcome of the rulemaking since it would not affect the rulemaking's result.

### 3. Performance Baseline from Which Carbon Capture Is Measured

UARG maintains that the EPA failed to give notice of the uncontrolled baseline emission rate (i.e., the emission rate of an uncontrolled coal-fired boiler) used as the starting point for calculating percent of partial carbon capture needed to meet a standard which is demonstrated at reasonable cost. UARG Petition p. 9 ("The proposed GHG NSPS did not in any way address the baseline emission rate for new SCPC units or analyze the proposed standard's achievability for such units"). Consequently, UARG asserts that it was necessarily impractical to address this issue in comments on the rulemaking, and that the EPA must grant reconsideration to afford opportunity for comment.

UARG's contention is mistaken. At proposal, the EPA indicated that "[a]ccording to the DOE NETL estimates, ... a new SCPC unit using bituminous coal would emit nearly 1,700 lb CO<sub>2</sub>/MWh ....". 79 FR 1468. "SCPC" is an acronym for "supercritical pulverized coal." The exact baseline value used by the EPA at proposal for a supercritical PC boiler using bituminous coal was 1,675 lb CO<sub>2</sub>/MWh.<sup>42</sup> In addition, the EPA recognized that "[t]he emissions would be higher for units utilizing subbituminous coal or lignite ..." 79 FR 1471. The EPA proposed that "highly efficient new generation with partial capture CCS" is the BSER for new fossil fuel-fired boilers and then estimated the cost of applying partial CCS to such a boiler emitting at the proposed emission level. See 79 FR 1476 (Table 6). The EPA then determined in the final rule that an "efficient new supercritical pulverized coal (SCPC) utility boiler implementing partial

<sup>41</sup> Memorandum of conversation between Dr. Nick Hutson (EPA) and Mr. Mike Monea (SaskPower), February 2, 2016; Pet. Exh. G p. 3.

<sup>42</sup> Exhibit ES-2 from "Cost and performance Baseline for Fossil Energy Plants Vol. 1: Bituminous Coal and natural Gas to Electricity," Revision 2, Report DOE/NETL-2010/1397 (Nov. 2010). The EPA cited to this source when presenting the baseline value ("nearly 1,700 lb CO<sub>2</sub> MWh") in the preamble to the proposed rule. 79 FR 1468 n. 178. We discuss below why an ultra-supercritical PC boiler may also be referred to as a "highly efficient supercritical pulverized coal (SCPC)" boiler.



carbon capture and storage (CCS)” is the BSER for such units and calculated the cost of applying CCS to such a boiler in the same way as at proposal.

The baseline values used by the EPA for the final rule were very similar to the value used at proposal: 1,620 lb CO<sub>2</sub>/MWh (for bituminous coal) and 1,737 lb CO<sub>2</sub>/MWh (for low rank coal). Final Preamble Tables 8 and 9; Achievability TSD Table 2.<sup>43</sup> Moreover, the proposed and final rule use the same methodology to estimate a baseline emission rate. For both the proposed and the final rule, the EPA used baseline estimates drawn from the DOE/NETL “cost and performance” studies for an efficient supercritical PC boiler. Emission estimates for units burning low rank coal were from the original (2011) “Volume 3b: Low Rank Coal to Electricity” report. Emission estimates for units burning bituminous coal were from the original (2011) “Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity” report for the proposal, while the emissions at final were from the updated (2015) version of that report. And, as at proposal, EPA estimated costs for applying partial CCS to a boiler emitting at the specified emission rate. 80 FR 64562 and Table 8.

The EPA thus fully presented all information necessary for comment on this issue at proposal. Specifically, the EPA gave notice of the potential level of performance for a highly efficient, uncontrolled supercritical boiler. Indeed, the EPA received a great deal of public comment on performance of highly efficient boilers without CCS, including quantification of potential levels of performance, confirming that the proposal provided ample notice of the issue.<sup>44</sup> The petition consequently fails to demonstrate that it was impractical to comment on this issue during the rulemaking.

UARG also fails to demonstrate that the issue it raises is of central relevance to the outcome of the rulemaking. UARG maintains that the baseline is not achieved in practice even by the two best performing plants, the Longview and Turk plants. As a result, according to UARG, the EPA has improperly estimated the rule’s costs since a plant with a higher uncontrolled baseline emission would require a higher level (i.e., a greater percentage) of partial carbon capture in order to meet the emission standard than the level predicted (and costed) by EPA in the final rule. Therefore, UARG claims that the level of the standard must be adjusted accordingly to be less stringent in order to stay within the cost level that the EPA has deemed to be reasonable. Pet. pp. 11-14.

The EPA disagrees with this assessment. First, as the EPA showed in the Achievability TSD, the Turk plant’s best monthly rate (1,725 lb CO<sub>2</sub>/MWh) was actually better than the EPA’s assumed uncontrolled emission rate (1,737 lb CO<sub>2</sub>/MWh). Achievability TSD p. 6. The plant’s best 12-month average rate (1,753 lb CO<sub>2</sub>/MWh) was only slightly higher (by less than 1 percent) than the EPA’s assumed uncontrolled emission rate. Id. And the plant’s worst 12-month average rate (1,817 lb CO<sub>2</sub>/MWh) was only 4.6 percent higher than the EPA’s estimated

<sup>43</sup> There is a typographical error in the final preamble at 80 FR 64594/3, stating “1,720” instead of the correct “1,620”.

<sup>44</sup> See RTC comment 6.3-423; see generally id. at comments 6.3-410 through 6.3-424 and 80 FR 64594-95; see also cases cited at n. 39 above, and *National Association of Manufacturers v. EPA*, 750 F. 3d 921, 926 (D.C. Cir. 2014) (notice adequate where petitioners’ comments show that they “had no problem understanding the scope of the issues up for consideration”).

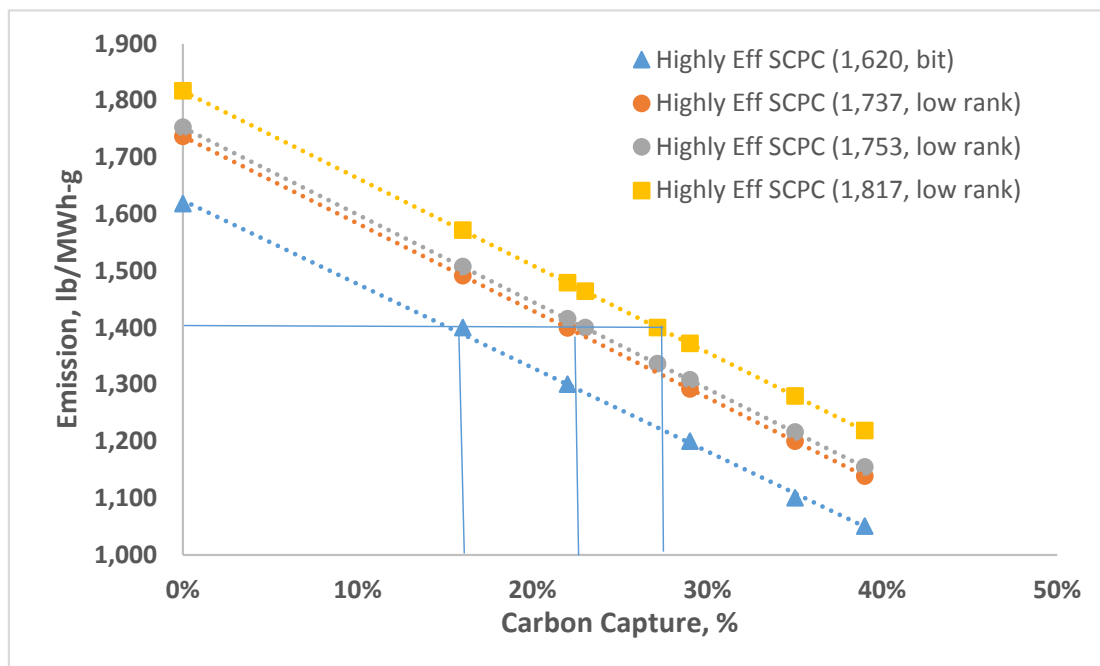
uncontrolled emission rate. Id. The Longview Power plant was identified as the best performing supercritical PC plant burning bituminous coal. Id. The best 12-operating-month average rate for the plant was only 1.9 percent higher than the EPA's assumed uncontrolled baseline. The highest 12-operating-month average for the Longview Power plant was about 11 percent higher than the EPA's assumed uncontrolled emission – but the Longview Power plant utilizes different steam conditions from those assumed by NETL in the cost and performance report used by the EPA. Id. As the EPA found, newly constructed, properly operated, and well maintained bituminous-fired plants that do incorporate the more efficient ultra-supercritical technology would expect to achieve better performance than the Longview Power plant – performance that is consistent with the baseline emissions assumed by the EPA. Id.

Further, even assuming that an ultra-supercritical plant (like Turk) could not make modest performance improvements to continue to match its documented monthly performance, the costs of meeting the standards with a slightly increased rate of CO<sub>2</sub> capture would continue to be reasonable. In order to assure that the final standard could be met without imposing unreasonable or exorbitant costs, the EPA finalized a standard with projected costs that are within the range of costs for other non-NGCC generation base load, dispatchable options. 80 FR 64566-567 (explaining why this is a reasonable comparison). Specifically, the EPA finalized a standard with projected costs that are similar in range to a new nuclear unit. The costs for a new highly efficient SCPC EGU emitting at 1,620 lb CO<sub>2</sub>/MWh (bituminous coal) and at 1,737 lb CO<sub>2</sub>/MWh (low rank coal) with partial capture meeting a standard of 1,400 lb CO<sub>2</sub>/MWh are projected to be \$92 – \$117 per MWh for a plant burning bituminous coal and to be \$95 - \$121 per MWh for a plant burning low rank coal. 80 FR 64562, Table 8. These projected costs are well within the ranges projected for a new nuclear unit – estimated to be \$87 - \$115 per MWh by EIA and estimated to be \$92 - \$132 per MWh by Lazard. Id. Small changes in the amount of CO<sub>2</sub> that must be captured to meet the final standard would result in small increases in cost, but would still be within the range of costs for a new nuclear plant.<sup>45</sup>

To show this, the EPA evaluated the cost of a new highly-efficient SCPC plant utilizing low rank coal to meet the final standard of performance of 1,400 lb CO<sub>2</sub>/MWh-g by implementing partial CCS. The baseline for such a new plant was assumed to range from 1,753 lb CO<sub>2</sub>/MWh-g to 1,817 lb CO<sub>2</sub>/MWh-g, a range consistent with the Turk facility's "best 12-month average" emission rate and its "worst (or highest) 12-month average emission rate". A comparison of the baseline emission rates and the CCS control levels required to meet the 1,400 lb CO<sub>2</sub>/MWh-g standard for the examples used in the final rule as well as for the range of performance for a unit consistent with those exhibited by Turk is shown in Figure 2 below.<sup>46</sup>

<sup>45</sup> Indeed, as shown in the following Section IV.A.4, even using the cost estimates in UARG Petition Exhibit J developed using their alternative methodology regarding scaling, which increases estimated costs, estimated costs remain within the range of the Lazard cost estimates for a new nuclear plant presented in preamble Table 8.

<sup>46</sup> This figure essentially adds a new highly efficient SCPC with Turk's "best 12-month average" and with Turk's "worst 12-month average" baselines to Figure 1 from the Achievability TSD. It should be noted that the EPA mentioned the Turk facility at proposal as an example of an ultra-supercritical unit, 79 FR 1468, further undercutting the Petitioner's claims of inadequate notice.



**Figure 2. Facility CO<sub>2</sub> emission (lb CO<sub>2</sub>/MWh) versus CO<sub>2</sub> partial capture (%)**

As can be seen in Figure 2, the “SCPC at 1,753 lb CO<sub>2</sub>/MWh-g” (consistent with Turk’s best 12-month average) capture line is essentially the same as the model plant highly efficient SCPC using low rank coal that was estimated in the final rule - requiring about 23 percent capture to meet the 1,400 lb CO<sub>2</sub>/MWh-g standard. A new plant exhibiting an emission level of 1,817 lb CO<sub>2</sub>/MWh-g (equivalent to Turk’s highest (or worst) 12-month average) would require about 27 percent capture to meet the 1,400 lb CO<sub>2</sub>/MWh standard. This information is summarized in Table 1 below.

This Table (which updates Table 2 from the Achievability TSD to include additional information relative to the performance of the Turk facility) shows that a new facility with baseline emissions consistent with Turk’s poorest performing 12-month average would have required approximately 27 percent partial capture to meet the 1,400 lb CO<sub>2</sub>/MWh-g standard and the cost of a capture system to achieve that capture level would range from \$98 - 125/MWh, which is in the range of projected cost for new nuclear (EIA at \$87 - \$115/MWh and Lazard at \$92 - \$132/MWh).<sup>47</sup> Similarly, if the highly efficient new SCPC EGU emitting at 1,620 lb CO<sub>2</sub>/MWh were to experience a higher than predicted emission rate consistent with the Turk “worst 12-month average” (i.e., + 5 percent), the unit, with an uncontrolled emission of 1,700 lb CO<sub>2</sub>/MWh, would require less capture than the 23 percent that was costed for the new unit using

<sup>47</sup> The range of Turk’s emission rates (from the best to the worst), coupled with the use of the 12-month rolling average compliance period, cover the range of conditions that new plants may be expected to face. See Achievability TSD, at pp. 1-2 (EPA-HQ-OAR-2013-0495-11771).



low rank coal (and certainly less than the 27 percent capture costed in the Table above for a new unit with the Turk “worst 12-month average” performance).<sup>48,49</sup>

**Table 1. Predicted Cost and CO<sub>2</sub> Emission Levels for a Range of Potential New Generation Technologies**

<b>New Generation Technology</b>	<b>Emission lb CO<sub>2</sub>/MWh-g</b>	<b>LCOE \$/MWh</b>
SCPC - no CCS (bit)	1,620	76 - 95
SCPC - no CCS (low rank)	1,740	75 - 94
SCPC - no CCS (low rank) – consistent with Turk’s best 12-month average	1,753	75 - 94
SCPC - no CCS (low rank) – consistent with Turk’s worst 12-month average	1,817	75 - 94
SCPC + ~16% CCS (bit)	1,400	87 - 115
SCPC + ~23% CCS (low rank)	1,400	95 - 121
SCPC + ~27% partial CCS (low rank)	1,400	98 - 125
Nuclear (EIA)	0	87 - 115
Nuclear (Lazard)	0	92 - 132
Biomass (EIA)	0	94 - 113
Biomass (Lazard)	0	97 - 116
IGCC	1,430	94 - 120
NGCC	1,000	52 - 86

<sup>48</sup> The UARG Petition also states that the EPA cost estimates should have included costs for a design (or compliance) margin, since plants are typically designed to perform below the level of a standard to account for performance variability. UARG Petition p. 11; the same point appears in the Petition of the State of Wisconsin at p. 4. The EPA cost estimates already are evaluated as a range and so could be up to 30 percent higher. 80 FR 64567. Including costs for a design margin (if needed) on top of this range would be overly conservative, effectively double counting costs. The 12-month averaging period also accounts for process variability. Id. at 64573.

<sup>49</sup> UARG quotes the 2015 NETL study as stating, “Actual average annual emissions from operating plants are likely to be higher than the design emissions rates shown due to start-up, shutdown, part-load operation, and performance degradation through maintenance cycles.” UARG Petition p. 11 (quoting NETL (2015), p. 1). The cost analysis just discussed makes clear that plants can adjust to higher baseline emissions by capturing greater amounts of CO<sub>2</sub>, but without significantly increasing costs, and, as a result, remaining within the range of overall costs that the EPA determined to be reasonable. The 2015 NETL study quoted by UARG went on to make a similar point. See NETL (2015), p. 1 (stating that meeting a required CO<sub>2</sub> emission limit by adjusting for increased emission rates due to, e.g., performance degradation through maintenance cycles, “does not have major cost implications,” except for plants with “low capture rates.” Because the control costs in the NETL study increase linearly starting with capture rates at 16 percent and higher, “low capture rates” below 16 percent are not relevant for this rulemaking.

UARG also overstates when it maintains that the level of carbon capture on which the rule is predicated is EPA's absolute measure of what is cost-effective for the standard. UARG Petition p. 9. In fact, the only costs the EPA did not determine would be reasonable were for full CCS (for either a PC or IGCC unit), and this was because estimated costs "are predicted to *substantially exceed* the costs for other dispatchable non-NGCC generating options that are being considered by utilities and developers". 80 FR 64596 (emphasis added); see also the similar finding at 79 FR 1477. In contrast, capturing an additional small increment (one to four percent) of CO<sub>2</sub> emissions would not result in costs that substantially exceed the other non-NGCC baseload, dispatchable technologies. Indeed, as just shown, the costs of such additional capture would remain within the same range as the cost of new nuclear generating technology. Moreover, the plant would have the ready option of co-firing a small amount of natural gas rather than increasing the rate of CO<sub>2</sub> capture, and thus incur virtually no increased cost. See 80 FR 64564-65. Finally, as noted in the final rule, the EPA expects, in most cases, that utilities and project developers who choose to construct a new coal-fired generating sources, will do so, at least in part, because of revenue opportunities from the sale of captured CO<sub>2</sub>. This potential revenue was not factored into the EPA's primary cost analysis and, therefore the costs presented in Table 1 above are likely to be conservative. See 80 FR 64563.

In addition, UARG claimed that it is "nonsensical" for the EPA to base its analysis for *supercritical* boilers combusting low rank coal on projections for *ultra-supercritical* boilers combusting subbituminous coal. Petition p. 11. This objection is purely semantic, and without substance. As the EPA explained at proposal, supercritical coal-fired boilers are designed and operated with a steam cycle above the critical point of water. *Any* boiler that operates above the critical point of water is a supercritical boiler. 79 FR 1468 n. 176. Ultra-supercritical (USC) is a term used to designate a coal-fired power plant design with steam conditions well above the critical point. *Id.* n. 182. The EPA proposed that "highly efficient new generation with partial capture CCS" is the BSER for new fossil fuel-fired boilers and then finalized that an "efficient new supercritical pulverized coal (SCPC) utility boiler implementing partial carbon capture and storage (CCS)" is the BSER for such units. Subcritical boilers operate using steam conditions below the thermodynamic critical point of water and supercritical boilers operate using steam conditions above the critical point of water. Adjectives such as "ultra" or "advanced" are used to describe SCPC units that are more advanced or more efficient than units operating with steam conditions that are just slightly above the thermodynamic critical point. In other words, an ultra-supercritical PC boiler may also be referred to as a "highly efficient supercritical pulverized coal (SCPC)" boiler.

More important, the issue is not the nomenclature used to describe the highly efficient SCPC boiler, but the quantified level of emissions assumed. As shown above, the level proposed and the level used in the final rule are roughly the same, were developed using the same methodology, and are reasonable. Neither UARG's notice issue nor its semantic objections justify reconsideration.

UARG also claimed that it is arbitrary for the EPA to use baseline emission rates for units burning subbituminous rather than lignite coal to represent the emissions performance of low

rank coals generally. (UARG Pet. at 12) They further noted that, although the EPA grouped these coal types together as “low rank” and treated them identically, the CO<sub>2</sub> emissions of EGUs combusting lignite are substantially different from those of EGUs combusting subbituminous coal and, therefore lignite units would need to capture a greater share of CO<sub>2</sub> emissions, at greater cost, to meet the final standard of 1,400 lb CO<sub>2</sub>/MWh-g.

The EPA agrees that the CO<sub>2</sub> emissions of EGUs combusting lignite are different from those of EGUs combusting subbituminous coal. However, the EPA disagrees that a new EGU utilizing lignite would need to capture a greater share of CO<sub>2</sub> emissions at greater cost to meet the final standard of 1,400 lb CO<sub>2</sub>/MWh-g because the emissions from units burning sub-bituminous coal and dried lignite are very similar. In the final rule, as UARG noted, the EPA very specifically referred to sub-bituminous and *dried* lignite as “low rank” coal. See, e.g., 80 FR 64513 (“A newly constructed, highly efficient SCPC utility boiler burning subbituminous coal or *dried* lignite will be able to meet this final standard of performance by capturing and storing approximately 23 percent of the CO<sub>2</sub> produced from the facility.”) (emphasis added). UARG contends that lignite drying technologies “are not sufficiently developed or commercially available to provide a viable CO<sub>2</sub> control option” (UARG Petition, Exhibit J at 3-1) and referenced a 2014 analysis prepared by the National Coal Council (NCC)<sup>50</sup>. The EPA disagrees. In fact, the cited reference supports the EPA’s approach. The NCC report states that “[c]oal drying with waste heat *is a commercially available option*, but one that not every plant can effectively deploy. [...] Less improvement would be expected for drying higher coal ranks ... because they tend to be much lower in moisture content than lignite.” (NCC report at 59, emphasis added) The NCC was essentially concluding that coal drying is a commercially available option for lignite, but is not likely effective for higher rank coals because of the lower moisture content. But, the EPA only identified coal drying for use with lignite – not with sub-bituminous or bituminous coals.

While it is difficult, if not impossible, to find real world examples that fully isolate the impact of burning subbituminous versus dried or undried lignite (because other variables including boiler design impact those rates), current emission data confirm the reasonableness of the EPA’s approach. Great River Energy has utilized lignite drying at its Coal Creek (North Dakota) plant with average 2015 emission rates of 2,145 lb CO<sub>2</sub>/MWh-g and 2,100 lb CO<sub>2</sub>/MWh-g for its units #1 and #2, respectively. These emissions are very similar to those from the sub-bituminous fired units at Colstrip (Montana) that had 2015 emission rates of 2,090 lb CO<sub>2</sub>/MWh-g and 2,115 lb CO<sub>2</sub>/MWh-g at its units #3 and #4, respectively. In contrast, emission rates in 2015 from a plant burning non-dried lignite, the Antelope Valley (North Dakota) plant, were distinctly higher. It is clear that the emissions from the Coal Creek units are more similar to those from the sub-bituminous fired units at Colstrip (Montana).<sup>51</sup>

Finally, UARG claims that the pre-CCS emission baseline should be calculated from the performance of SCPC boilers (i.e., boilers not fully optimized for efficiency) rather than from the

<sup>50</sup> *Reliable and Resilient: The Value of Our Existing Coal Fleet*, prepared by the National Coal Council (June 2014).

<sup>51</sup> All emissions data are from the EPA’s Air Markets Program Data (AMPD) available at <https://www.epa.gov/airmarkets>.

most efficient boilers like the Turk facility. UARG Petition pp. 11-12.<sup>52</sup> This objection is mistaken, and therefore not of central relevance to the outcome of the rulemaking. The argument is that the EPA “may not focus solely on the best performing units to determine whether an NSPS is achievable”, and that to be achievable, the EPA must demonstrate that the standard can be met under the range of operating conditions that may reasonably occur. *Id.* p. 11. Of course a best system of emission reduction may reasonably reflect performance of optimized control technologies, and if one means of control results in lower emissions, the EPA may reasonably identify that system as a basis for BSER. See 80 FR 64539; see also *Sierra Club v. Costle*, 657 F. 2d 298, 326 (D.C. Cir. 1981) (amount of emissions reduction is obviously relevant in determining a best system). Thus, the EPA may reasonably select as BSER a system that includes a type of boiler designed for optimized operating efficiency.

#### 4. Application of NETL Scaling Methodology

UARG claims that the EPA’s estimates of the capital cost of CCS are unreasonably low. UARG Petition pp. 14-17. Most of the argument reiterates points made in comments to the rulemaking, among them, that the EPA should have placed greater weight on capital costs in its analysis,<sup>53</sup> should have used costs of current projects rather than estimated costs, and should have assumed that new projects will incur ‘first-of-a kind’ costs rather than ‘n<sup>th</sup>-of-a-kind’. None of these issues are new, and all have been addressed by the EPA in the preamble to the final rule and in comment responses. See, e.g. 80 FR 64566-571. Since all of these objections can, and were, raised during the rulemaking, it was obviously practical to do so within the meaning of section 307(d)(7)(B). The EPA is accordingly not granting reconsideration on these objections.

UARG further objects to the methodology by which costs were scaled in the NETL 2015 cost estimates. UARG contends that the estimated capital costs for implementing partial CCS are invalid because they claim that NETL misapplied cost scaling principles to extrapolate costs for partial capture from estimated costs for full capture.

<sup>52</sup> It is evident that the ultra-supercritical technology is adequately demonstrated. It is deployed both domestically (the Turk plant), and internationally. See Comments of American Electric Power (EPA-HQ-OAR-2013-0495-10938) p. 117, documenting operation or construction of ultra-supercritical units in Poland, Germany, Malaysia, Japan, and Denmark from as early as 1998. Numerous commenters, among them petitioners here, urged its adoption as BSER (rather than partial CCS). Comments of UARG (EPA-HQ-OAR-2013-0495-10938) pp. 69 and 77; Comments of American Electric Power (EPA-HQ-OAR-2013-0495-10938) pp. 114-15; Comments of Alstom (EPA-HQ-OAR-2013-0495-9033) p. 6. The EPA received no significant adverse comment on its statement in the proposal that “[g]eneration technologies representing enhancements in operational efficiency (e.g., supercritical or ultra-supercritical coal-fired boilers or IGCC units) are clearly technically feasible....” 79 FR 1435.

<sup>53</sup> The Petition states incorrectly that “[t]he proposed GHG NSPS did not address the capital cost of partial CCS” (UARG Petition p. 14). Estimated capital costs are presented in NETL 2011 at 8-9, 35-7, and then presented for all of the individual study cases at sections 4.2.5 and 4.2.6 and in NETL 2013 at pp. 8, 35-37, and 39 and then presented for all of the individual study cases in the report at section 3.2.4. In the proposal, the EPA relied on the levelized cost of electricity (LCOE) as the cost metric, and LCOE includes capital costs. 79 FR 1435 n. 9. Commenters urged the EPA to consider capital costs as a separate metric, and in the final rule, the EPA did so (along with continued analysis using the LCOE metric), and concluded that this capital cost metric also supported the EPA’s determination that the costs of partial CCS are reasonable. 80 FR 64559-60.

However, both EPA and NETL have clearly presented that the capital cost estimates documented in their reports reflect an uncertainty range of -15 percent to +30 percent - consistent with AACE Class 4 cost estimates (i.e., a feasibility study). The NETL cost estimates are intended to represent the next commercial offering, and relied on vendor cost estimates for component technologies.

As part of the NETL partial CCS studies, it was necessary to estimate the cost of some lower capacity or “scaled down” carbon capture equipment when little or no cost data are available for such smaller equipment. In the 2015 report, NETL specified that a power law with an exponent of 0.6 was assumed to scale 40 percent of the cost of the CO<sub>2</sub> capture system based on the inlet gas volumetric flow to the process and the remaining 60 percent of the cost scaled based upon the captured CO<sub>2</sub> mass flow rate in accordance with Quality Guidelines for Energy System Studies procedures. This power law scaling approach is a very common application of what is referred to as the “six-tenths rule”. In their classic chemical engineering textbook, Peters and Timmerhaus described this rule and its use as follows:

It is often necessary to estimate the cost of a piece of equipment when no cost data are available for the particular size of operational capacity involved. Good results can be obtained by using the logarithmic relationship known as the six-tenths-factor rule, if the new piece of equipment is similar to one of another capacity for which cost data are available. ... However, the application of the 0.6 rule is an oversimplification of a valuable cost concept since the actual values of the cost capacity factor vary from less than 0.2 to greater than 1.0 ... . *Because of this, the 0.6 factor should only be used in the absence of other information.*<sup>54</sup> (emphasis added)

Following the advice of Peters and Timmerhaus, it is common practice for design engineers to use the 0.6 factor “in the absence of other information” when estimating equipment costs by scaling. The UARG petition acknowledges this normative approach, but maintains that “other information” may justify deviating from it. UARG Petition p. 16 and Exh. J at 4-5 to 4-6.

UARG first suggests that because an EPRI Technical Assessment Guide (“Electricity Supply – 1993 (EPRI TR-102276-V1R7, Vol. 1)) recommends the use of exponents from 0.24 to 0.28 for “power generation equipment”, the cost analysis “*may merit* scaling exponents considerably less than the 0.6 value used by DOE/NETL” for large, capital intensive components such as flue gas absorbers and stripping towers. Exh. J at 4-5 (emphasis added), citing to EPRI Guidance at p. 8-11. UARG then provides an analysis showing how the selection of alternative scaling exponents would affect the projected costs. They also provide a case where a “design margin” is included (i.e., a larger portion of the flue gas is treated as compared to that assumed in the NETL study). In UARG’s “alternative projections”, their example in “Row E” (Exhibit J, Table 4-2), includes an adjustment to the scaling exponents and a “design margin”. They claim that this “alternative projection” – according to their calculation – would add \$6/MWh to EPA’s LCOE projection. They then claim that this “alternative projection” cost invalidates EPA’s conclusion that the cost of partial CCS is reasonable.

<sup>54</sup> Peters, M.S., and Timmerhaus, K.D.; *Plant Design and Economics for Chemical Engineers*, Third Edition, McGraw-Hill Book Company, New York, NY USA, 1980 (emphasis supplied).



UARG's reference to the EPRI Technical Assessment Guide for power plants is not persuasive. The Guide is for power plant equipment. UARG specifically mentions "foundations, high pressure steam components, and precision equipment such as steam turbines" in their petition. See Exh. J, p. 4-5. As the EPA explained in the rulemaking, a carbon capture system is more similar to a chemical plant than to the equipment traditionally found at a coal-fired power plant. In the post-combustion system, which is the BSER here, liquid solvents are used to separate CO<sub>2</sub> from the flue gas using chemical absorption or chemisorption. In this separation process, flue gas is processed through the CO<sub>2</sub> scrubber and is absorbed by the liquid solvent and then released by heating to form the high purity CO<sub>2</sub> stream. See generally 80 FR 64549 and other sources there cited. This process has nothing to do with generating electricity. It is a chemical process to yield a high purity chemical, in this case, CO<sub>2</sub>. Guidance applicable to power plants does not support a deviation from the 0.6 rule-of-thumb to scaling cost estimates for this chemical plant type of process. In fact, Schnelle, et al., recommend the use of the six-tenths factor rule for scaling air pollution control technologies:<sup>55</sup>

A key consideration for equipment costing is the economy of scale. In general, the cost of equipment does not double as the size of the equipment doubles. In fact, the general cost relationship for equipment as a function of the equipment capacity is referred to as the *six-tenths factor rule* ... .

UARG also claims that the NETL cost estimates are invalid because they applied the power-law scaling correlation (i.e., the 0.6 rule-of-thumb) for mass rates of CO<sub>2</sub> processing below the range of 445,000 to 689,000 lb/hr, claiming that the NETL Quality Guidelines provide that the power law scaling correlation is valid only when used within that range. Petition Exh. J at 4-6. However, the NETL guidelines do not say that. Instead, the NETL guidelines state that "[t]here are limitations on the ranges that can accurately be addressed by the scaling approach. ... Care should be taken in applying the scaling factors when there is a large percentage difference between the scaling parameters."<sup>56</sup> The NETL guidelines thus do not provide that use of the power law correlation is invalid outside the recommended ranges – but, rather, they instruct users to take care when applying the cost correlation in those instances. Similarly, Peters and Timmerhaus advise that:

In general, the cost-capacity concept should not be used beyond a tenfold range of capacity, and care must be taken to make certain the two pieces of equipment are similar with regard to type of construction, materials of construction, temperature and pressure operating range, and other pertinent variables.

A CO<sub>2</sub> flow rate that is "beyond a tenfold range of capacity" would be one that is less than 44,500 lb CO<sub>2</sub>/hr and none of the NETL costing evaluations are less than that amount. In addition, the EPA did "[take] care ... to be certain the two pieces of equipment are similar" because partial CCS involves the same equipment as full capture.

<sup>55</sup>Schnelle, K.B.; Dunn, R.F.; and Ternes, M.E.; *Air Pollution Control Technology Handbook, Second Edition*, CRC Press, Taylor & Francis Group, LLC, Boca Raton, FL (2016). (emphasis in the original)

<sup>56</sup>DOE/NETL *Quality Guidelines for Energy System Studies: Capital Cost Methodology* (DOE/NETL – 341/013113 at p. 18 (attached as Exh. K to the UARG Petition)).

Moreover, even if the EPA were to accept UARG's alternative analysis – which we do not – we would not reach the conclusion that the resulting re-estimated costs are unreasonable. First, even UARG acknowledges that their alternative costs still fall within the LCOE ranges reported for nuclear (Nuclear/Lazard)<sup>57</sup> and are therefore reasonable using the rationale applied in both the proposal and in the final rule. Second, the UARG analysis fails to acknowledge the uncertainty that has already been included in the NETL cost analysis. As mentioned earlier, the capital cost estimates documented in the reports reflect an uncertainty range of -15 percent to +30 percent - consistent with AACE Class 4 cost estimates (i.e., a feasibility study). Third, as was also mentioned earlier, even if UARG's alternative projections were convincing, they have again incorrectly assumed that the EPA has defined a “break point” of cost reasonableness. That is not the case. The EPA promulgated a final standard of performance with a projected cost range that is consistent with projected cost ranges for other competing generation technologies. However, the EPA did not find – nor ever suggest – that costs above those ranges are unreasonable or exorbitant. In fact, the EPA only found that because the costs of new generation technologies implementing *full CCS* were *significantly* beyond the projected cost for competing generating technologies, full CCS was not the best system of emission reduction. Finally, cost increases could be either ameliorated or eliminated by co-firing with a minor amount of natural gas, as noted above. See generally 80 FR 64564-565.

Overall, UARG has not convincingly established why the costing exponents that they have chosen for their “alternative projections” are preferred over the very common “rule-of-thumb” 0.6 exponent that NETL adopted in the absence of better information. UARG has also not convincingly established that the use of the power law cost correlation is “invalid” when applied beyond the capacity ranges recommended by NETL. Further, even if the EPA were to adopt UARG's “alternative projection”, the EPA is still not convinced that the resulting costs are unreasonable or exorbitant. Therefore, the EPA does not find these issues to be of central relevance and is denying the petition for reconsideration.

##### 5. Inclusion of the Heat Input from Duct Burners in the Definition of “Base Load Rating”

The EPA is denying UARG's petition for reconsideration of the final rule's definition of “base load rating.” While the EPA agrees that it was impracticable for UARG to raise its objection during the public comment period, UARG has failed to explain how its objection is of central relevance to the outcome of the final rule. Contrary to UARG's suggestion, a petitioner seeking reconsideration must demonstrate that its “objection” is of central relevance, not merely that the objection discusses an “issue” of central relevance. UARG Pet. at 17 (“The issue is centrally relevant to the Rule because it implicates the fundamental question of what units are subject to the GHG NSPS.”). In fact, the EPA's decision to include the heat input from duct burners in the definition of “base load rating” was not only reasonable, but advantageous to industry and its members, including UARG. The final definition provides certain stationary combustion turbines with greater flexibility to generate and sell to the grid larger amounts of electricity without triggering more stringent regulatory requirements. Finally, no more than a few, if any, combustion turbines will become subject to the rule's requirements as a result of the

<sup>57</sup> UARG's “alternative projection” for the “SCPC + ~16% CCS (bit)” case increases the cost from \$92 - \$117 per MWh to \$98 - \$123 per MWh. The estimated cost for a new nuclear unit, as estimated by Lazard, is \$92 - \$132 per MWh.

change, and the record demonstrates that even those few turbines will be able to achieve the standard of performance.

At the outset, UARG does not meet its burden of demonstrating central relevance. UARG objects to the inclusion of the heat input from duct burners in the definition of “base load rating” by noting alleged inconsistencies with the proposed rule and the criteria-pollutant NSPS for stationary combustion turbines. However, UARG does not explain why these alleged inconsistencies, which (as explained below) exist for good reason, are problematic. UARG also cites to comments it submitted on the proposed emission guidelines for existing fossil-fuel-fired EGUs, but the citation provided consists of an irrelevant discussion of why Building Block 1 (i.e., heat rate improvements) is allegedly unachievable for *coal-fired EGUs*, not combustion turbines.<sup>58</sup> The EPA reviewed UARG’s comments on the emission guidelines in full,<sup>59</sup> but the only mention of duct burners is in a similarly irrelevant discussion of why Building Block 2 would allegedly require existing natural gas combined cycle (NGCC) units to fire their duct burners on a continuous basis.<sup>60</sup> The inclusion of the heat input from duct burners in the definition of “base load rating” relates to the final rule’s applicability requirements, however, not the achievability of the BSER. Because UARG has not provided the EPA with sufficient information to evaluate its conclusory objection to the definition of “base load rating” as it applies to stationary combustion turbines, the EPA finds that UARG’s objection is not of central relevance to the outcome of the rule.

In any event, the definition of “base load rating” in the final rule is reasonable for several reasons. First, the definition is consistent with other changes the EPA made to the proposal. The proposed rule included subcategories for small and large stationary combustion turbines, consistent with the criteria-pollutant NSPS.<sup>61</sup> At the time of proposal, the EPA’s rationale for subcategorizing based on size was that NGCC units that use aeroderivative combustion turbine engines were less efficient than NGCC units that use large industrial frame combustion turbine engines. 79 FR 1486. Specifically, the small subcategory covered units with a heat input of 850 MMBtu/h or less, including both aeroderivative and smaller industrial frame combustion turbine engines. The large subcategory covered units larger than 850 MMBtu/h, all of which are large industrial frame combustion turbine engines.

At proposal, the EPA defined “base load rating” as “100 percent of the manufacturer’s design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel (heat input from duct burners is not included).” 79 FR 1509. If the EPA had included the supplemental heat input from duct burners in the definition of “base load rating” at proposal, some aeroderivative and small industrial frame combustion turbines likely would have exceeded the 850 MMBtu/h threshold and become subject to the more stringent

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<sup>58</sup> See Comments of the Utility Air Regulatory Group on the United States Environmental Protection Agency’s Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule at 212 (Dec. 1, 2014), EPA-HQ-OAR-2013-0602-22768.

<sup>59</sup> Even though the EPA undertook such a review here, the EPA notes that the CAA does not require the agency to search through a petitioner’s previously-filed comments to account for incorrect citations.

<sup>60</sup> Comments of UARG at 206.

<sup>61</sup> 40 CFR Part 60, Subpart KKKK.



standard for large units, which was based on the supposedly more efficient operation of large industrial frame combustion turbines.

In response to comments, however, the EPA eliminated the proposed size-based subcategories in the final rule and, consistent with a noticed alternative approach, 79 FR 1459-61; 79 FR 34979-81, established a single emission standard for all natural gas-fired combustion turbines operating at base load. The EPA concluded that size-based subcategories were not appropriate for a CO<sub>2</sub> emission standard because (1) no clear cut-point exists between “small” and “large” units; (2) size-based subcategories could unduly influence the development of future NGCC offerings; (3) actual operating and design data showed a relatively weak correlation between turbine size and CO<sub>2</sub> emission rates, with the emission-rate variability among similar size units far exceeding any variability that could be attributed to a difference in size; (4) most existing small units had already demonstrated emission rates below the proposed emission standard for large units; and (5) the lower design efficiencies of some small units were primarily related to model-specific design choices in the turbine engine and heat recovery steam generator, not inherent limitations in the ability of small units to achieve comparable efficiencies to large units. 80 FR 64608-09. By eliminating the size-based subcategories, the EPA’s prior concern—that including the heat input from duct burners in the definition of “base load rating” would cause some aeroderivative and small industrial frame combustion turbines to be included in the large unit subcategory—was no longer an issue.

Second, the final definition of “base load rating” actually benefits industry. As the EPA explained in the final rule, the definition of “base load rating” includes the heat input from duct burners to accurately account for the potential electric output of the affected unit. 80 FR 64608. This definition complements both the finalized operations-based subcategorization approach and the exemption for industrial combined heat and power (CHP)<sup>62</sup> facilities.

In regards to the former, the final rule established non-base load and base load subcategories for natural gas-fired stationary combustion turbines. The base load subcategory is subject to an output-based emission standard of 1,000 lb CO<sub>2</sub>/MWh-g that reflects modern, efficient NGCC technology. The non-base load subcategory, on the other hand, is subject to a less-stringent input-based emission standard of 120 lb CO<sub>2</sub>/MMBtu that reflects the use of clean fuels. The distinction between the base load and non-base load subcategories is based on an affected unit’s net-electric sales and potential electric output. Potential electric output is determined, in part, by multiplying a unit’s design efficiency by its base load rating. At a given design efficiency, units with a higher base load rating will have a higher potential electric output. The higher a unit’s potential electric output, the more electricity that unit can sell to the grid before being classified as a base load unit subject to the more stringent output-based standard. In other words, by including the heat input from duct burners in the definition of “base load rating,” the EPA increased the amount of electricity that a non-base load unit with duct burners can sell to the grid. This result favors industry, and UARG has not objected to it.

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<sup>62</sup> “Combined heat and power unit or CHP unit, (also known as ‘cogeneration’) means an electric generating unit that use[s] a steam generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.” 40 CFR 60.5580.

In regards to CHP facilities, the final applicability criteria are not intended to cover industrial CHP units that are primarily intended to provide useful thermal output (e.g., steam) to a host facility. 80 FR 64533-35. To differentiate between industrial and utility CHP units, the EPA used a similar approach to the one used to distinguish between base load and non-base load units, i.e., a comparison between net-electric sales and potential electric output. As described previously, potential electric output is determined, in part, by multiplying a unit's design efficiency by its base load rating. CHP units often include duct burners to satisfy the steam demands of the host facility. Thus, the inclusion of the heat input from duct burners in the definition of "base load rating" means that CHP units with duct burners will have a higher base load rating and a higher potential electric output than they would otherwise. The result is that industrial CHP units with duct burners can sell more electricity to the grid without becoming subject to the final rule's requirements. This result also favors industry, and UARG has not objected to it.

Third, few, if any, new NGCC units are likely to become subject to the final rule's requirements as a result of the change to the proposed definition,<sup>63</sup> and even these units will not be disadvantaged because they will be able to achieve the 1,000 lb CO<sub>2</sub>/MWh-g standard. There are two types of duct burners: (1) small duct burners designed to recover lost output during periods of high ambient temperatures and (2) large duct burners designed to create additional output during all types of conditions.<sup>64</sup> Combustion turbines combust less fuel when ambient temperatures are higher than ISO<sup>65</sup> conditions (288 Kelvin (15 °C), 60 percent relative humidity, and 101.3 kilopascals pressure), reducing electric output. Relatively small duct burners (e.g., less than 5 percent of the potential heat input of the affected unit) are often used to make up this shortfall. Owners and operators typically only run these smaller duct burners during periods of peak summer demand, when ambient temperatures are high. To calculate a unit's base load rating, however, an owner or operator must determine the amount of fuel that the unit can combust at steady state and ISO conditions.<sup>66</sup> Because the base-load-rating calculation is based on the affected unit's operation at ISO conditions, not ambient conditions, the heat input from this type of smaller duct burner will not affect the calculation.

In contrast, large duct burners (e.g., greater than 5 percent of the potential heat input of the affected unit) are used to create additional steam turbine output at ISO conditions, meaning the final definition of "base load rating" could potentially affect combustion turbines equipped with this type of burner. However, (where no exemption applies) the final rule only applies to units that (1) have a base load rating greater than 250 MMBtu/h of fossil fuel and (2) serve a

<sup>63</sup> For example, UARG could not identify any example existing stationary combustion turbines that would be impacted by the change. See Utility Air Regulatory Group, Petition for Reconsideration of EPA's "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (Oct. 23, 2015), at 17 (Dec. 22, 2015).

<sup>64</sup> Backlund, Jon and Froemming, Jim; *Thermal & Economic Analysis of Supplementary Firing Large Combined Cycle Plants*, <http://www.coen.com/library/technical-papers/thermal-economic-analysis-of-supplementary-firing-large-combined-cycle-plants/>.

<sup>65</sup> ISO refers to the "Industrial Organization for Standards." See <http://www.iso.org/iso/home.html>.

<sup>66</sup> "Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU *at ISO conditions*." 40 CFR 60.5580 (emphasis added).

generator capable of selling greater than 25 MW of electricity to the grid. 40 CFR 60.5509(a)(1)-(2). Most new NGCC units will have a base load rating *greater* than 250 MMBtu/h even *without* the heat input from large duct burners. In fact, the smallest NGCC units capable of meeting the 25 MW criterion will have a heat input rating of approximately 200 MMBtu/h (not including the heat input from duct burners).<sup>67</sup> The record for the final rule shows that NGCC units with a base load rating of only 190 MMBtu/h can comfortably achieve the final rule's 1,000 lb CO<sub>2</sub>/MWh-g standard with a design compliance margin<sup>68</sup> of 11 percent.<sup>69</sup> Therefore, while a handful of smaller NGCC units might exceed the 250 MMBtu/h threshold and become affected units once the heat input from their duct burners is accounted for, even these units will not be disadvantaged. As a result, UARG's conclusory objections are unfounded, and the EPA is denying reconsideration on this issue.

#### 6. Objections Related to Identity of Reporting Entities

UARG's final objection relates to the mechanics of electronic reporting. UARG complains that the final rule restricts the person submitting reports to a "Designated Representative", whereas the proposal would have allowed anyone qualifying as an "owner or operator" to submit reports. UARG claims it had no notice of this possibility, and that there are substantive reasons that a designated representative should not submit reports. UARG Petition p. 18.

UARG has not met either of the requirements for granting reconsideration on this issue. The EPA proposed that owners/operators of affected EGUs submit reports. 80 FR 1452. UARG submitted comments on the issue, noting among other things that the proposal was meant to be consistent with e-reporting under the acid rain program, and that under that program a "designated representative" files reports. UARG Comments p. 194. The comment continued that under various applicable rules, not all designated representatives are owners/operators, and that EPA should deal with this issue in the final rule so that "any individual who meets the definition of 'owner or operator'" can certify and submit reports. Id. p. 195. The EPA responded in the final rule by allowing reports to be submitted by a designated representative, a person appointed as alternate designated representative, or a person authorized by either of these. Any of these can be an owner/operator. Section 60.5555(d) and (e); see also RTC 12.4-6 indicating that the final rule was being clarified to address UARG's comment.

It is clear both from EPA's proposal and from UARG's comment that it had adequate notice of the question of who reports, and indeed, their comment directly addressed the issue of the relationship between owner/operator and designated representative. Moreover, this issue is not of central relevance to the rule, since it deals with a nuance of rule implementation, not with

<sup>67</sup> While there is sufficient oxygen in the combustion turbine engine exhaust to theoretically support duct burners with a maximum heat input value greater than the combustion turbine itself, for practical reasons, the duct burners used in electric-only NGCC units are generally limited to approximately 20 percent of the heat input of the affected unit. Newell, Samuel A., et al.; *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants* in PJM with June 1, 2018 Online Date, <https://www.pjm.com/~media/documents/reports/20140515-brattle-2014-pjm-cone-study.ashx>.

<sup>68</sup> A compliance margin is the difference between a unit's performance capability and the actual standard of performance.

<sup>69</sup> Gas Turbine World Efficiency Combined Cycle Efficiency, EPA-HQ-OAR-2013-0495-11888.

whether the standard of performance reflects a best system of emission reduction which is adequately demonstrated.

In any case, UARG's objection lacks substantive merit. UARG reiterates that there are distinctions between the acid rain and NSPS programs such that only owner/operators should report under the NSPS program. Petition pp. 18-19. Even assuming this is the case, the final rule obviates UARG's concern because it allows owners/operators to report if affected EGUs wish to do so. Specifically, the rule provides that for affected EGUs subject to the acid rain program, either a designated representative, authorized designated representative, or person authorized by either of these, can report. 60 CFR section 60.5555(d). Thus, even if they are not already one and the same, a designated representative or authorized designated representative can in turn authorize the owner/operator<sup>70</sup> to file. UARG notes that section 60.5555(d) begins by stating that the report "shall be submitted by", and misreads the provision to assume that this means only designated representatives can file. UARG Petition p. 19. Section 60.5555(d)(3) makes clear that a designated representative can in turn authorize any other entity, including an owner/operator, to file.

Identical provisions apply in the case of affected EGUs not subject to the acid rain program: filing can be done by a designated representative, authorized designated representative, or an entity authorized to file by the designated representative. Section 60.5555(e).

Since this objection does not satisfy any of the requirements in the Act for granting reconsideration, the EPA is denying it. Moreover, since the final rule allows owner/operators to file, it appears to provide UARG with all the relief it seeks on this issue so that there is no basis for objection.

#### *B. Response to AEP Petition*

AEP essentially objects to the EPA's characterization of its experience in retrofitting one of its plants, the Mountaineer Plant (New Haven, WV), with partial CCS in a demonstration project. The EPA viewed (and views) that experience as providing support for partial CCS being an adequately demonstrated technology. AEP claims that it and others submitted extensive comment that EPA failed to adequately address.

The EPA cited to AEP's own figures in finding that the project achieved CO<sub>2</sub> capture rates on the slip stream of from 75 to 90 percent. The EPA also cited AEP's own FEED report<sup>71</sup> on how the demonstration project could be scaled up to full scale capture. 80 FR 64552, 64557; see also 79 FR 1436 and 1475 (discussing the Mountaineer project at proposal). The EPA also quoted AEP Chief Executive Officer's own praise of the project's performance: "we feel that we have demonstrated to a certainty that the carbon capture and storage is in fact viable technology for the United States and quite honestly for the rest of the world going forward." (80 FR 64556) The EPA likewise quoted Alstom senior Vice President Joan MacNaughton's 2011 public statement that "[t]he Validation Plant at Mountaineer demonstrated the ability to capture up to 90

<sup>70</sup> "Owner/operator" is defined in the general provisions at 40 CFR 60.2. The definition is capacious and does not limit the ability of a designated representative to delegate filing authority to an owner/operator.

<sup>71</sup> FEED = Front End Engineering Design

percent of the CO<sub>2</sub> from a stream of the plant's emissions. The technology works." RTC Chapter 6 at 6-152. (Alstom was a partner in the demonstration project, which used its chilled ammonia carbon capture technology.)<sup>72</sup>

AEP did indeed submit comments in this rulemaking maintaining that the Mountaineer project did not demonstrate that partial CCS is BSER. Among other things, those comments maintained that the project was too small in its scale to demonstrate that partial CCS is adequately demonstrated at commercial scale, and that there were extensive cost overruns on the project, many of them attributable to difficulties in siting monitoring wells used to assure integrity of the CO<sub>2</sub> sequestration area. Comments of AEP (May 8, 2014) pp. 80-83. The EPA responded to all of these comments, noting among other things that both AEP's own FEED study and the NETL studies set out in point-by-point, system-by-system detail how the capture technology could be scaled up to full-scale<sup>73</sup>, why the costs at the project were not indicative of costs at a new facility (for example, since the project was a retrofit, the project presented siting issues (including siting for monitoring wells) that could be avoided for a new plant)<sup>74</sup>, and generally why partial CCS is not exorbitantly costly.<sup>75</sup>

AEP does not maintain (nor could it do so plausibly) that it lacked notice of the issue to which it now objects. The EPA also believes that the agency reasonably characterized the performance of the Mountaineer project, reasonably responded to AEP's public comments, and accurately quoted and interpreted the public statements of AEP and Alstom executives characterizing the performance of the Mountaineer project. See, e.g., RTC response 2.1-235. The project does provide strong support for the technical feasibility of partial CCS, including at commercial scale. Moreover, the costs incurred at the project are not indicative of costs for a new source given that the project is a retrofit. Consequently, in addition to being untimely, AEP's objection is not of central relevance to the outcome of the rulemaking, and the EPA is therefore denying the petition to reconsider.

AEP also maintains that the record contains no information showing that Boundary Dam Unit 3 is capable of achieving the promulgated standard since it had operated for less than one year at the time of promulgation.<sup>76</sup> The EPA's basis for finding that the standard is achievable is fully set out at 80 FR 64573-74 and in the Achievability TSD. The EPA gave ample notice that it regarded Boundary Dam as a plant preparing to utilize full scale CCS, and noted that its design level and reported initial performance were well in excess of the rate of carbon capture on which the standard of performance is predicated. 79 FR 1435; 80 FR 64549-50. AEP's objection

<sup>72</sup> See also RTC response 6.3-107 (more quotes from AEP and Alstom executives praising performance of CCS); id. at response 6.3-320 (Alstom Senior Vice President MacNaughton states publicly that "coal with CCS is cost competitive with the cost of electricity generated by other low- or no-carbon energy sources"; the full text of the press release from Alstom Vice President MacNaughton is at EPA-HQ-OAR-2013-0495-11320).

<sup>73</sup> See, e.g. Final Preamble section V.G.3; RTC response 6.3-23 at p. 6-17.

<sup>74</sup> See, e.g. 80 FR 64573; RTC responses 6.3-93, 6.3-247 (at pp. 150-151), 6.3-259 (at p. 167), 6.3-272 (at p. 183).

<sup>75</sup> RTC response 6.3-286.

<sup>76</sup> UARG raises a similar point at p. 11 of its Petition. The exhibits to UARG's own petition show that BD3 met the U.S. standard in its initial year of operation. See III.A.1 above.



therefore fails to demonstrate that there was lack of opportunity to comment during the rulemaking or that the objection is of central relevance to the rulemaking's outcome.

*C. Response to Ameren Petition*

Ameren's petition deals virtually in its entirety with objections to the section 111(d) emission guidelines. The petition states correctly that the section 111(b) NSPS is related to the emission guidelines, but the only specific objection raised to the section 111(b) standards is a claim that partial CCS is not adequately demonstrated, an issue on which there was obvious opportunity to comment during the rulemaking. Since the petition states no legitimate grounds for granting reconsideration, the EPA is denying it.

*D. Response to State of Wisconsin Petition*

The State of Wisconsin largely reiterates comments it made during the rulemaking, but claims that the EPA did not adequately respond to them. These include comments regarding achievability of the proposed NSPS; consistency of the standard with individual BACT determinations (including a BACT determination made by the State Of Wisconsin for the Elm Road power plant); CCS' status as an "emerging technology" that cannot be BSER; and lack of geologic storage capacity in Wisconsin, which the State asserts puts Wisconsin at a competitive disadvantage. Wisconsin Petition Attachment 1 at 1. The EPA in fact addressed all of these issues, and Wisconsin's comments regarding them, in the rulemaking. See e.g., RTC comment responses 9.5-2, 6.3-237, 6.3-291, 6.3-332 and 80 FR 64631-32 (responses relating to BACT determinations and choice of partial CCS as BSER)<sup>77</sup>; 2.1-147, 2.1-149, 2.1-157, 2.1-238, 6.3-23 (responses relating to "emerging technology"); 6.3-60; 6.3-72, 6.3-84, 6.3-99, 6.3-100, 6.3-251,

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<sup>77</sup> The State asserts that its 2012 determination that full CCS was not BACT for the Elm Road coal fired plant undercuts EPA's technical determination that partial CCS is BSER for new plants. This assertion lacks a reasoned basis. First, individual state BACT determinations, while relevant, do not constrain federal technical determinations in the different context of section 111 standards (80 FR 64631). Second, this particular BACT determination is not properly comparable to the new source standard. The determination involved application of CCS to an existing facility, not to a new source. Thus, the BACT determination was triggered by an existing source's request to burn sub-bituminous rather than bituminous coal. The State determined that although full CCS was a technically feasible control technology for CO<sub>2</sub>, the technology was economically infeasible for two reasons: there was insufficient land available at the existing site to sequester captured carbon, and the nearest sequestration site was out of state, necessitating very high transport costs. See generally, "ANALYSIS AND PRELIMINARY DETERMINATION FOR THE CONSTRUCTION PERMIT FOR THE PROPOSED MODIFICATION OF TWO COAL FIRED POWER BOILERS FOR Wisconsin Electric Power Company, d.b.a WE ENERGIES-OAK CREEK STATION, LOCATED AT 11060 S CHICAGO RD., OAK CREEK, MILWAUKEE COUNTY, WISCONSIN" Construction Permit No.: 12-SDD-047 (October 22, 2012), pp. 13-14. Thus, this determination is consistent with the EPA's determination in the section 111(d) emission guideline rulemaking and the section 111(b) rulemaking that full CCS is not BSER for existing or modified power plants. The determination in the permitting proceeding also is at odds with the State's position here that CCS is not a technically feasible technology. See also RTC Response 6.3-291 where the EPA gave a similar response to the similar comment regarding a BACT determination for an Iowa facility.

2.1-228 and 80 FR 64549-54, 64556-57, 64575-82 (responses relating to availability of sequestration capacity and demonstration of partial CCS technology). The petition thus fails to state any grounds requiring EPA to reconsider any of these issues.

The State also maintains that EPA miscalculated costs relating to transport of captured CO<sub>2</sub> for Wisconsin new sources, largely because the EPA cost estimates assume transport for 62 miles (100 km) rather than the 270 miles Wisconsin sources would need to use. Wisconsin Petition Attachment 1 pp. 1-2 and n.9. In fact, a New Source Performance Standard is developed on a nationwide, not state-by-state basis, and the EPA's evaluation of costs was reasonable. The record shows, and indeed Wisconsin does not contest (or even address) that 95 percent of the largest CO<sub>2</sub> sources are within 50 miles of a potential storage reservoir. The State also does not contest or even address the other potential compliance paths noted in the administrative record: CO<sub>2</sub> storage can be provided by enhanced oil recovery (EOR); a new source can be sited out-of-state proximate to a sequestration site (for example, in Illinois, the example given in the State's petition) and still provide electricity via 'coal-by-wire' arrangements. These arrangements are documented for distances considerably greater than the 270 miles the State refers to in its Petition. See 80 FR 64572, 64579-81, 64582-83; RTC comment responses 6.3-251; 6.3-277; responses in unit 6.3.4.

In addition to a coal-by-wire compliance alternative, the EPA noted that coal plants could co-fire natural gas and meet the standard without the need for CCS (partial or otherwise). 80 FR 64564. Wisconsin challenges this determination in its Petition, although it (properly) does not claim that it lacked opportunity to comment on the issue, or that its objection is of central relevance to the outcome of the rulemaking. Wisconsin asserts that co-firing at rates of 30 percent or higher is not an adequately demonstrated technology and so this compliance path may not exist for some sources. Specifically, the Petition states that "EPA's own reference documents show that co-firing natural gas up to 30 percent (on a heat input basis) has not moved beyond the design/pilot state; therefore co-firing gas at 40 percent has not been adequately demonstrated". Wisconsin Petition Attachment 1 p. 2, referring to the EPRI technical report "Gas Cofiring Assessment for Coal Fired Utility Boilers" cited by the EPA at 80 FR 64564 n. 288 ("EPRI Cofiring Assessment"). This contention is mistaken. The EPA found that natural gas co-firing rates of up to 40 percent could be achieved by using a combination of natural gas reburning and supplemental gas firing. 80 FR 64564/3. The EPRI Cofiring Assessment indicates that these rates of co-firing are demonstrated and achievable. EPRI Cofiring Assessment at pp. 2-4, 2-5, 2-35. The petition mistakenly confused these well-established technologies, which are the ones the EPA evaluated and costed, with a different technology, coal/gas co-firing burners (discussed in unit 2.6 of the EPRI Cofiring Assessment) (See, e.g., EPRI Cofiring Assessment unit 2.6 at pp. 2-40 to 41; Executive Summary p. 1; Executive Summary p. xvii "The largest number of applications and the longest experience time is with reburning and supplemental gas firing."). Because these co-firing techniques introduce natural gas at different locations - in a boiler's primary combustion zone (supplemental gas co-firing) and in the upper regions of the primary furnace above the primary coal combustion zone (reburning techniques) - they can be implemented in combination.

The State of Wisconsin also argued that coal boiler operators would likely need to fire even more than 40 percent natural gas to be in compliance with the final standard, since 1) they need to have a sufficient compliance margin below the standard, and 2) the EPA's assumed base

rate of 1,618 lb CO<sub>2</sub>/MWh-g is lower than what has been achieved in practice. There is no technological reason that a new boiler cannot be designed to accommodate an increased level of natural gas co-firing (there is at least one existing EGU with the capacity to fire 100 percent coal or 100 percent natural gas – and to co-fire combinations of the two). Further, even if a new EGU needed to (or chose to) co-fire more than 40 percent natural gas to meet the standard of performance, the cost would be well within the range of costs that the EPA found to be reasonable (See 80 FR 64565, Table 9).

The petition also maintains that EPA cannot consider natural gas co-firing as an alternative compliance path in any case because doing so impermissibly redefines the source. Wisconsin Petition Attachment 1 p. 2. This issue was raised in public comment and the EPA has already responded. RTC Comment and Response 2.1-103; 2.1-213; 2.1-214; 2.4-6. Thus, the objection is untimely.

It also lacks central relevance. In brief, redefining a source is a concept that has developed exclusively in the context of the Prevention of Significant Deterioration (PSD) program, under different statutory criteria. PSD determinations are case-by-case preconstruction requirements that require the incorporation of the “best available control technology” (BACT) at the time of construction of a new major emitting facility or as part of a major modification<sup>78</sup> of an existing facility. Because BACT applies at the preconstruction stage on a case-by-case basis and generally requires the installation of control technology, it is appropriate, though not required, for a permitting authority to limit the scope of BACT to avoid frustrating the fundamental purpose and to consider the inherent design of such projects on a case-by-case basis.

Under the PSD program, there is no absolute prohibition against redefining the source,<sup>79</sup> but rather an EPA-developed policy of caution concerning fundamentally redefining the source and disrupting the basic business purpose of a project in the context of BACT determinations.<sup>80</sup> The State’s argument consequently fails even if one were to accept its logic that the concept applies to establishing section 111(b) standards of performance.

The State is in fact in error in its contention that the redefining the source concept is even relevant in the section 111(b) context. Under section 111(b), the Administrator identifies a list of adequately demonstrated control options, selects the best of those control options after considering cost and other factors, then selects an achievable limit for the category through the application of the BSER across the industry. The BSER for purposes of section 111(b) is not limited to technology that can be built into a specific source because affected sources have already been constructed. Rather, it is generally based on pollution control systems that can be implemented by a new source. A best system of emission reduction certainly can entail some

<sup>78</sup> Note that the requirements of a NSR “modification” are distinct from the standards for “modifications” finalized under CAA section 111(b).

<sup>79</sup> PSD and Title V Permitting Guidance for Greenhouse Gases at 27 (March 2011) (“EPA does not interpret the CAA to prohibit fundamentally redefining the source and has recognized that permitting authorities have the discretion to conduct a broader BACT analysis if they desire’); *In re Knauf Fiberglass*, 8 E.A.D. 121, 136 (EAB 1999) (“redefinition of the source is not always prohibited”).

<sup>80</sup> *In re Prairie State Generating Company*, 13 E.A.D. 1, 15-28 (EAB 2006).



measure of fuel substitution.<sup>81</sup> Moreover, natural-gas co-firing here is an alternative compliance path noted by EPA, but not part of the Best System of Emission Reduction, see 80 FR 64564, so any analogy with the BACT process fails in any case.

Indeed, as EPA has already explained, natural gas co-firing has been used for years as a mechanism for reducing air pollution from coal-fired boilers. 80 FR 64564; see also 79 FR 1471. Consequently, the EPA reasonably determined that natural gas co-firing could constitute an alternative compliance path for meeting the 1,400 lb CO<sub>2</sub>/MWh standard of performance, that this alternative compliance pathway is generally available and obviates issues of access to geologic sequestration and EOR capacity, and that the statute does not preclude this type of finding. The State's objection is consequently not of central relevance to the outcome of the rulemaking. Consequently, the EPA is denying these aspects of the petition.

Finally, Wisconsin argues that the final rule set a standard of performance for natural gas-fired stationary combustion turbines operating as base load units that cannot be achieved by simple cycle technology. Wisconsin makes no effort to explain how its objection meets the criteria for reconsideration under section 307(d)(7)(B).

At proposal, the EPA provided clear and adequate notice that the BSER for base load turbines was natural gas combined cycle (NGCC) technology. The EPA specifically rejected simple cycle technology as the BSER for this subcategory, noting that even advanced simple cycle units "have a base load rating of 1,150 lb CO<sub>2</sub>/MWh, which is higher than the base load rating emission rates of 830 and 760 lb CO<sub>2</sub>/MWh for the conventional and advanced NGCC model facilities, respectively." 79 FR 1430, 1485. The EPA also explained that "NGCC has a lower cost of electricity than simple cycle turbines at intermediate and high capacity factors" (i.e., base load operation). 79 FR 1485. The EPA received numerous comments on this issue. See Response to Comments Chapter 7.4.2 at 7-36 to 7-40 (EPA-HQ-OAR-2013-0495-1186); see also 80 FR 64,614/1 (summarizing comments).

In the final rule, the EPA explained:

Many commenters mistakenly thought that the EPA proposed to require some simple cycle combustion turbines to meet an emission standard of 1,000 lb CO<sub>2</sub>/MWh-g, a level that they assert is unachievable. On the contrary, the EPA is not finding that NGCC technology and a corresponding emission standard of 1,000 lb CO<sub>2</sub>/MWh-g is the BSER for simple cycle turbines. Instead, the EPA is finding that NGCC technology is the BSER for base load turbine applications. This means that if an owner or operator wants to sell more electricity to the grid than the amount derived from a unit's nameplate design efficiency calculated as a percentage of potential electric output, then the owner or operator should install a NGCC unit. If

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<sup>81</sup> Indeed, Congress amended section 111(a) in 1990 to remove the language that standards of performance reflect the best technological system and achieve a percent reduction in emissions, 80 FR 64537 n. 124, confirming that non-technological controls such as fuel substitution could be part of that best system. Similarly, under the CAA section 112 National Emission Standard for Hazardous Air Pollutant program, the EPA is mandated to consider "substitution of materials" in assessing what standards reflect performance of maximum achievable control technology. See CAA section 112(d)(2)(A).

the owner or operator elects to install a simple cycle turbine instead, then the practical effect of our final standards will be to limit the electric sales of that unit so that it serves primarily peak demand, not to subject it to an unachievable emission standard.

80 FR 64,615/2.

Because the grounds for Wisconsin's objection did not arise after the public comment period and Wisconsin has not explained how its concerns are centrally relevant, the EPA is denying reconsideration on this issue.

*E. Response to EELI Petition*

EELI's Petition is premised entirely on undocketed email communications between a single former EPA official and various members of non-governmental organizations (NGOs). Several dozen emails are attached as exhibits to the petition in support. EELI claims that these emails show that the whole rulemaking process was tainted by "*ex parte* communications", that the agency decision maker was impermissibly biased, and that the contacts between the single EPA official and NGO personnel constituted an advisory committee established in contravention of the provisions of the Federal Advisory Committee Act (FACA). The petition asserts lack of opportunity to raise its objection during the rulemaking because some of the emails in question were not yet available. According to the petition, the objection raised is of central relevance to the rulemaking's outcome because the rule's outcome was determined by non-agency personnel. EELI Petition p. 4 ("[t]his direction from private parties was not simply manifest in the final rule; it documents a predetermination of the material substance of the rule, controlled by non-agency personnel").

This petition is significantly incorrect as a matter of both law and fact. First, the concept of *ex parte* communication does not apply to informal rulemakings,<sup>82</sup> either under the Administrative Procedure Act or under the procedural requirements of the Clean Air Act. *Sierra Club v. Costle*, 657 F. 2d 298, 400-402 (D.C. Cir. 1981).<sup>83</sup> The reason is that, unlike adjudicative proceedings, informal rulemakings involve policymaking, quasi-legislative types of determinations benefitting enormously from "continuing contact with a regulated industry, other affected groups, and the public". *Id.* at 401. Informal rulemakings stand in contrast with adjudicative, trial-type proceedings where conflicting claims to a valuable privilege militate in

<sup>82</sup> "Informal rulemakings" (as opposed to rulemakings required by statute to be made on the record after opportunity for an agency hearing) involve notice by the agency via the Federal Register, and opportunity for public comment to that notice. 5 USC section 553(b) and (c).

<sup>83</sup> See also Administrative Conference of the United States "*Ex parte* communications in informal rulemakings" (June 10, 2014) stating "Informal communications between agency personnel and individual members of the public have traditionally been an important and valuable aspect of informal rulemaking proceedings conducted under section 4 of the Administrative Procedure Act (APA), 5 U.S.C. § 553. Borrowing terminology from the judicial context, these communications are often referred to as "*ex parte*" contacts.<sup>[1]</sup> Although the APA prohibits *ex parte* contacts in formal adjudications and formal rulemakings conducted under the trial-like procedures of 5 U.S.C. §§ 556 and 557,<sup>[2]</sup> 5 U.S.C. § 553 imposes no comparable restriction in the context of informal rulemaking". Available at <https://www.acus.gov/recommendation/ex-parte-communications-informal-rulemaking>

favor of insulation of the decision-maker. *Id.* at 400. EELI cites *Home Box Office v. FCC*, 567 F.2d 9 (D.C. Cir. 1977) as its (sole) support. EELI Petition p.5. However, that case does not apply to informal rulemakings. *Sierra Club*, 657 F.2d at 402 (“Later decisions of this court ... have declined to apply *Home Box Office* to informal rulemaking ... and there is no precedent for applying it to the procedures found in the Clean Air Act....”).

The EPA was also not required to docket these pre-proposal communications. Section 307(d)(3) of the Clean Air Act indicates that “[a]ll data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule.” However, when a proposed rule is not based on any information or data arising from a particular contact, the information is not required to be docketed. See *Sierra Club*, 657 F.2d at 407. That is the case here. First, all of the emails attached as exhibits to the petition are from 2011 and relate to a different proposal than the one that led to the standard at issue here. In 2012, the EPA proposed a new source standard for coal-burning boilers, but withdrew that proposal and commenced a new proceeding. 77 FR 22392 (April 13, 2012); 79 FR 1352 (January 8, 2014) (withdrawing the 2012 proposal). The different proceeding at issue here was proposed at 79 FR 1430 (January 8, 2014). Second, the potential standards discussed in the emails are unrelated to those that the EPA proposed. Thus, the emails discuss a potential standard of 1,600-2,100 lb CO<sub>2</sub>/MWh based on burning natural gas along with coal. The standards that the EPA proposed were 1,000 lb CO<sub>2</sub>/MWh based in the withdrawn proposal on constructing only natural gas combined cycle plants (i.e., not burning coal at all) (77 FR 22392), or (in the new proposal) on the performance of a control technology, carbon capture and sequestration, which uses a chemical process to capture CO<sub>2</sub> and convert it to a phase state where it can be piped to a sequestration site for permanent disposition. 79 FR 1446, 1469-75. There is no requirement to docket information on regulatory alternatives that the agency never proposed, never solicited comment on, and never otherwise pursued.

Moreover, the EPA did disclose all factual and methodological information underlying the proposal, indeed exhaustively so. See, e.g., 79 FR 1462-1485 (legal rationale for proposal; rationale for proposed selection of partial CCS as BSER; cost information; information on geologic sequestration of captured CO<sub>2</sub>). Even were the suggestions of outside parties reflected in a proposal (which is not the case here), then what would matter would be the content of that proposal, and whether the data and methodology underlying the proposal are disclosed. This is the information that is critical to a proposed rule (see CAA section 307(d)(3)(A)-(C)), not the identity of individuals making suggestions.<sup>84</sup>

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<sup>84</sup> As it happens, EPA staff sought out the views of numerous parties from industry and academia, as well as the environmental community, in crafting the new source performance standards. See e.g., Meeting with Lignite Energy Council on 05/09/14 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-9674>; EPA Meeting with Golden Spread Electric Cooperative on June 17, 2014 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-11064>; Meeting between EPA and Representative Tom Sloan on January 6, 2014 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0078>;

The further suggestion that the EPA's decision is the product of impermissible bias is untenable. See generally RTC Response 2.4-19. Petitioners need to make a "clear and convincing showing of an unalterably closed mind on a matter critical to disposition of the proceeding". *Lead Industries Ass'n v. EPA*, 647 F. 2d 1130, 1178 (D.C. Cir. 1980). At most, the Petition shows that one EPA official, who was not in the lead office developing the rulemaking, sought out pre-proposal comment on regulatory alternatives that the agency never pursued, which alternatives were considerably less stringent than the standards the EPA actually proposed. Rhetorical flourishes notwithstanding, the Petitioner has failed to make any semblance of the requisite showing here.

For all of these reasons, the EPA is denying this Petition.

## V. Conclusion

The new source standards require a new coal-burning power plant to reduce carbon dioxide emissions to a level reflecting both the most highly efficient boiler design, and partial capture and sequestration of carbon dioxide. Carbon capture and sequestration is a proven technology, with a history of reliable use at coal-fired plants and other industrial sources. At the level of capture on which the standard of performance is predicated, partial capture and sequestration is available at reasonable cost. An unprecedented coalition of major industrial entities (including Peabody Energy, Arch Coal, Archer Daniel Midland, Occidental Petroleum), major NGOs, unions (including the AFL-CIO), and diverse states (including Kentucky, Maryland, and Michigan) recently stated that "CCUS [carbon capture utilization and storage] represents an essential component of our nation's strategy for achieving greenhouse gas emission reductions. Without widespread deployment of CCUS technologies, we will simply fail to meet global mid-century goals for mitigating carbon emissions from electric power generation and a wide range of industrial activity."<sup>85</sup> The same impressive coalition noted that "[c]apturing and

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USEPA Meeting with EEI Regarding CAA 111(b) and (d) Proposals for GHG Emissions from EGUs, February 3, 2015 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-11270>;  
 Meeting with NRDC Regarding Proposed Carbon Pollution Standard for New Power Plants, December 18, 2014 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-11269>;  
 AES Meeting on 05-13-14 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-10947>;  
 Meeting between USEPA and Union representatives on July 26, 2013  
<http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0061>;  
 Attendee List from USEPA Meeting with GE on December 16, 2013  
<http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0071>;  
 Meeting with Environment America on 05-09-14 <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-9673>;  
 Meeting Memorandum <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-11806>;  
 Meeting between USEPA and Power4Georgians on February 13, 2013  
<http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0063>.

<sup>85</sup> Letter of February 3, 2016 from coalition members to the Honorable Kevin Brady and the Honorable Sander Levin, urging retention of the section 45Q tax credit for carbon capture and utilization; see also

utilizing power plant and industrial CO<sub>2</sub> through EOR [enhanced oil recovery] yields additional American oil from existing wells that would otherwise not be accessed thereby expanding domestic reserves and reducing imports. The United States independent oil and gas industry is the world leader in CO<sub>2</sub>-EOR and could produce billions of barrels of additional American oil from existing fields, while safely and permanently storing billions of tons of CO<sub>2</sub>.<sup>86</sup>

The standards of performance also serve to promote further development and implementation of carbon capture and sequestration technology. It is a documented phenomenon that national rules requiring large emission reductions have resulted in significant upswing in inventive activity to develop and perfect needed emission control technologies. 80 FR 64575.

The new source performance standard will not be an impediment to construction of new coal-burning capacity. Indeed, availability and deployment of carbon capture technology could prove a lifeline to the industry. As the scourge of climate change becomes increasingly manifest, the ability to use coal without substantially adding to CO<sub>2</sub> emissions will be more and more important. The new source performance standard sends a strong signal that low-emitting coal-burning capacity is feasible, and that coal can thereby have an important place in a lower-carbon energy future. As American Electric Power stated, “AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation.” 80 FR 64572.<sup>87</sup> The petitions for reconsideration here present no information that cause the EPA to deviate from these findings and conclusions.

The petitions for review of UARG, Ameren, AEP, State of Wisconsin, and Energy and Environment Legal Institute are denied in their entirety.

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parallel letter from the same coalition to Senators Orrin Hatch and Ron Wyden (April 4, 2016). These letters are part of the record for this action.

<sup>86</sup> Id.

<sup>87</sup> The quote is from “CCS LESSONS LEARNED REPORT American Electric Power Mountaineer CCS II Project Phase 1”, prepared for the Global CCS Institute project #PRO 004, January 23, 2012, p. 2. (EPA-HQ-OAR-2013-0495-11680).